PB84-199553

Simple Transmission Network Planning Method
Wisconsin Power Plant Impact Study

Wisconsin Univ.-Madison

Prepared for

Environmental Research Lab.-Duluth, MN

Jul 83

U.S. Department of Commerce
National Technical Information Service
NTIS

PB84-199553

EPA-600/3-83-061
July 1983

A SIMPLE TRANSMISSION NETWORK PLANNING METHOD

Wisconsin Power Plant Impact Study

by

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Grant No. R803971

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This study was conducted in cooperation with

Water Resources Center,
Wisconsin Power and Light Company,
Madison Gas and Electric Company,
Wisconsin Public Service Corporation,
and Wisconsin Department of Natural Resources

ENVIRONMENTAL RESEARCH LABORATORY-DULUTH
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
DULUTH, MINNESOTA 55804

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TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO.
EPA-600/3-83-061

2.

3. RECIPIENT'S ACCESSION NO.
PB84 199553

4. TITLE AND SUBTITLE
A Simple Transmission Network Planning Study:
Wisconsin Power Plant Impact Study

5. REPORT DATE
July 1983

6. PERFORMING ORGANIZATION CODE

7. AUTHOR(S)
Farrokh Albuyeh & James Skiles

8. PERFORMING ORGANIZATION REPORT NO.

9. PERFORMING ORGANIZATION NAME AND ADDRESS
Dept. of Electrical and Computer Engineering
University of Wisconsin
Madison, WI 53706

10. PROGRAM ELEMENT NO.

11. CONTRACT/GRANT NO.
R803971

12. SPONSORING AGENCY NAME AND ADDRESS
Environmental Research Laboratory
U.S. Environmental Protection Agency
Duluth, MN 55804

13. TYPE OF REPORT AND PERIOD COVERED

14. SPONSORING AGENCY CODE
EPA/600/03

15. SUPPLEMENTARY NOTES

16. ABSTRACT

In the process of evaluation and comparison of the proposed alternative power generation sites, the transmission network required to carry power effectively and reliably from the plant to the load centers requires careful consideration. The existing transmission network must be reinforced to accommodate these generation expansion plans and then should further be expanded as the load level increases. Therefore, a need exists for a transmission network expansion algorithm to provide a transmission network expansion plan over several planning periods for a given load and generation profile.

The transmission network planning method developed here uses the same logical steps followed in practice by utility planning engineers and uses sensitivity matrices to supplement the experience of the planning engineers. The network is modeled either by a DC power flow model or by a Fast-Decoupled AC power flow model. To every branch a cost factor is associated which reflects capital costs and operational cost of the branch. Also included in the cost factor, is an environmental cost associated with increasing the capacity of the branch. The environmental cost in turn may include such factors as political and geographical constraints. To enable the planner to concentrate on a small area of interest, or to reduce the system size, a classical network reduction algorithm is utilized to model the external system by simple equivalents.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
DIS.		

18. DISTRIBUTION STATEMENT	**19. SECURITY CLASS** *(This Report)* Unclassified	**21. NO. OF PAGES** 170
	20. SECURITY CLASS *(This page)* Unclassified	**22. PRICE**

EPA Form 2220-1 (Rev. 4-77) PREVIOUS EDITION IS OBSOLETE

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FOREWORD

The U.S. Environmental Protection Agency (EPA) was established to coordinate our country's efforts toward improving and defending the quality of the environment. These efforts depend greatly on research to monitor environmental change and to determine health standards.

One project the EPA is supporting through its Environmental Research Laboratory in Duluth, Minnesota, is the study "The Impacts of Coal-Fired Power Plants on the Environment." The Columbia Generating Station, a coal-fired power plant near Portage, Wisconsin, has been the focus of all field observations. This interdisciplinary study is conducted by the Environmental Monitoring and Data Acquisition Group of the Institute for Environmental Studies at the University of Wisconsin-Madison and involves investigators from many departments at that same university. Several utilities and state agencies also are cooperating in the study: Wisconsin Power and Light Company, Madison Gas and Electric Company, Wisconsin Public Service Corporation, Wisconsin Public Service Commission, and Wisconsin Department of Natural Resources.

A simple network-expansion method especially suited for comparative studies of alternate expansion schedules for generation and transmission is presented. The steps in this algorithm follow the logical steps that are carried out in practice during network expansion. An overload logic expands the network to withstand outages without any resulting overloads and a voltage-correction algorithm ensures that voltage magnitudes stay within allowable limits during outages. No claim is made for the optimality of the expansion plans produced by this method, but they will be similar to those obtained by the planning engineer for a given network.

Norbert A. Jaworski
Director
Environmental Research Laboratory
Duluth, Minnesota

ABSTRACT

In the process of evaluation and comparison of the proposed alternative power generation sites, the transmission network required to carry power effectively and reliably from the plant to the load centers requires careful consideration. The existing transmission network must be reinforced to accommodate these generation expansion plans and then should further be expanded as the load level increases. Therefore, a need exists for a transmission network expansion algorithm to provide a transmission network expansion plan over several planning periods for a given load and generation profile.

The transmission network planning method developed here uses the same logical steps followed in practice by utility planning engineers and uses sensitivity matrices to supplement the experience of the planning engineers. The network is modeled either by a DC power flow model or by a Fast-Decoupled AC power flow model. To every branch a cost factor is associated which reflects capital costs and operational cost of the branch. Also included in the cost factor, is an environmental cost associated with increasing the capacity of the branch. The environmental cost in turn may include such factors as political and geographical constraints. To enable the planner to concentrate on a small area of interest, or to reduce the system size, a classical network reduction algorithm is utilized to model the external system by simple equivalents.

The planning algorithm begins with an algorithm to automatically rank and select the contingency cases for the system contingency analysis study. After the contingency analysis study, lines are checked for overloads. In cases where overloads exist, a sensitivity matrix is utilized to locate the most economical branch reinforcements to alleviate the overloads. This process is repeated until no overloads remain. The contingency analysis algorithm is carried out again and this time nodes in the network are checked for voltage magnitude deviations from specified limits. Adjustments to bus reactive power injections, needed to bring voltages to within the allowable limits, are found and corrections are made. The program then steps to the next planning period by setting the load and generation profile to its predicted value and the process is repeated until the horizon year--the final planning period--is reached. A line removal subroutine is developed to check the usefulness of new lines after passage of a given number of planning periods, and to remove unnecessary lines.

This algorithm provides a valuable tool for the planning engineers and for regulatory agencies involved in the evaluation of alternative system expansion plans.

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ACKNOWLEDGMENTS

Appreciation is expressed to Dr. A. Ravindran of the Wisconsin Public Service Commission for his assistance in providing data.

Acknowledgment is due to the Wisconsin Upper Michigan Systems' (WUMS) Transmission Planning Task Force, especially to Mr. Donald Brown of Wisconsin Power and Light Co., for assistance and providing data.

The authors gratefully acknowledge the financial support provided by the U.S. Environmental Protection Agency, the Wisconsin Electric Utilities Research Foundation, and the University of Wisconsin Graduate School.

SECTION 1

INTRODUCTION

The problem of planning transmission-network expansion is one of the most difficult problems in electrical-network studies. The main difficulties can be attributed to four factors: (1) The large number of possible expansion alternatives; (2) the complexity of reliability criteria, which may vary from system to system and company to company; (3) the existence of many external cost variables--i.e., environmental costs--that cannot be quantified easily; (4) uncertainties in predicting future power demand.

Traditionally, attempts to develop automatic algorithms for planning network expansions have treated the problem as a mathematical optimization problem, optimizing a performance index subject to a set of equality and inequality constraints. These techniques are difficult to evaluate because few of them have been developed beyond the experimental stages.

In practice, network expansion is carried out methodically by the utilities' planning engineers, based on their working experience with the system. The system is expanded to satisfy given reliability criteria. Outages are simulated on critical branches, and for a predicted load profile the network is expanded by a standard procedure. The network-expansion plans produced by automated network-expansion algorithms do not always match those obtained by the standard procedure, which may be one reason for the planning engineers' reluctance to use automated methods.

When proposed new or expanded power-generation sites are being evaluated and compared, one of the most important factors to be considered is the transmission network associated with the sites. The network should be designed to carry power effectively and economically, with a given degree of reliability, from the site to the load centers. For these types of problems, a simple network-expansion algorithm is needed.

The method developed in this report is an automated technique with logical steps that may closely parallel those taken in practice by the planning engineer. This algorithm divides the problem into two parts: (1) Network reduction and (2) network planning. Network reduction is needed to focus attention on parts of the system that are of interest by representing the external system by simple equivalents. The network-planning algorithm uses sensitivity matrices to simulate the engineers' experience. The main features of the algorithm are: (1) Contingency tests--using a sensitivity matrix, lines are ranked according to their expected effect on the network and contingency tests are carried out accordingly; (2) overload logic--using a sensitivity matrix, a line or lines are selected that will alleviate overloads with least cost; (3) voltage correction logic--adjustments to bus reactive power to eliminate voltage deviations from specified limits are found by using sensitivity matrices; (4) line removal logic--unnecessary lines are removed from the network. The method is intended to serve as an additional tool for planning engineers, but does not substitute for judgment and experience. It may also be valuable to regulatory agencies evaluating alternate plans proposed by utilities.

Before the proposed method is described, a review of the basic concepts in power systems is presented (Section 3) and current planning methods are outlined. Section 4 briefly reviews load-flow or power-flow methods, network-reduction methods are discussed in Section 5, and network-expansion methods are reviewed in Section 6. Section 7 contains a detailed description of the proposed method and examples of systems' studies are presented in Section 8. Appendix A shows the mathematical derivations for the sensitivity models. Appendices B through E present computer outputs for sample studies on various systems using both AC and DC models. Finally, Appendices F and G show the listings of planning programs for a DC model and an AC model, respectively.

SECTION 2

CONCLUSIONS AND RECOMMENDATIONS

A simple network-expansion method especially suited for comparative studies of alternate expansion schedules for generation and transmission is presented in this report. The steps in this algorithm follow the logical steps that are carried out in practice during network expansion. An overload logic expands the network to withstand outages without any resulting overloads and a voltage-correction algorithm ensures that voltage magnitudes stay within allowable limits during outages. No claim is made for the optimality of the expansion plans produced by this method, but they will be similar to those obtained by the planning engineer for a given network.

The new ideas presented in this document are: (1) A network-expansion technique using sensitivity matrices to obtain economical expansion plans; (2) use of the "B" matrix from the fast-decoupled load-flow algorithm in an iterative procedure that provides bus reactive power adjustments to bring voltage magnitudes to within specified limits; and (3) an automatic contingency selection procedure that ranks branches according to their expected effect on the system and greatly reduces the total number of contingency case studies (Albuyeh and Skiles 1981).

The sample expansion studies in Appendices B through E illustrate the application of the algorithms developed to produce expansion plans. Of the two models developed, the AC model is more flexible since a more accurate model of the network is utilized and information on voltage magnitudes in addition to line flows is obtained. Furthermore, the voltage-correction logic incorporated in the AC model may provide a more realistic expansion plan than that obtained by the DC model. On the other hand, the DC model is simpler and faster and since the DC load-flow model is non-iterative, convergency difficulties are avoided in ill-behaved networks.

Several factors should be considered when applying the automated technique outlined in this report. First, interaction between the planner and the planning program is needed. The planning engineer should input ideas into the program on a yearly basis and should not rely on the program to expand the network automatically over many planning periods. Second, the expansion plans depend heavily on generation schedules. Various generation and load schedules should be considered for the network under study, although such studies are usually done using forecasted peak loads. Third, various ratings of network components such as normal summer, winter, or emergency ratings should be considered. Furthermore, ratings on other components such as breakers or line traps may limit the flow in a branch.

Fourth, the reliability criterion incorporated in the program is a single contingency criterion; that is, outages of single lines from every branch are studied. Other contingency cases can be handled at the discretion of the user. For example, generator outages can be simulated by rescheduling real power values at corresponding buses. Double-line contingencies can be simulated by removing from the input data the data for the appropriate lines. Fifth, the program does not have the capability to add new rights-of-way to the network, nor does it have the capability to introduce nodes into the system that are not included initially. The network planner can provide this flexibility as follows: All potential but initially unused rights-of-way can be represented as lines of high impedance until they are actually used and new but unused nodes can be presented as nodes connected to the network by potential rights-of-way. Sixth, abnormal expansion plans--i.e., the addition of too many lines over a given right-of-way or of unusual amounts of susceptance at a given bus--should signal to the planner that other measures should be tried. Alternatives are the use of lines of higher voltage, changes in transformer taps, or additional lines for voltage support.

To simplify the load-flow model, transformer tap changing under load (TCUL) has not been incorporated. This absence does not pose a serious limitation to the model; however, further work on this algorithm should include TCUL in the load-flow model. Including network reduction and network planning into one combined program is desirable to overcome the need for several editing programs and to eliminate the restrictions on system size. Other network-reduction techniques, especially those which permit recalibration of the equivalent network to account for changes in the system (such as the linearized-reduction method), should also be incorporated into the program.

Sparse matrix techniques have not been implemented in the planning programs because the sensitivity matrix utilized is a non-sparse matrix. Additional research is required to investigate means to overcome this difficulty. These means may include area sensitivity matrices, which would show the first-order sensitivities in an area of interest only, or the use of additional types of sparse sensitivity matrices.

Although no automated planning algorithm can replace the planning engineer, the algorithm presented here can be a valuable tool for the planning engineer. Combined with the engineer's expertise, this algorithm can provide practical expansion plans.

SECTION 3

POWER SYSTEMS

A power system is typically composed of generating stations connected to load centers by a transmission network. The transmission system interconnects all the generator stations and all the major loading points in the system. In addition, via interties, transport of energy can take place to or from other power systems. The transmission system, in general, has a multiple-loop structure with several multiply-interconnected voltage levels rather than the radial structure common to distribution systems. The loop structure permits some flexibility in routing of energy on various links and offers more path combinations for contingencies.

DEFINITIONS

In terms of phasor quantities of voltage $\overline{V} = V_{rms} \angle \alpha$ and current $\overline{I} = I_{rms} \angle \beta$, the complex power $\overline{S}$ is

$$\overline{S} = \overline{V}\,\overline{I}^{*}. \tag{1}$$

Substituting for $\overline{V}$ and $\overline{I}$ in Eq. (1), we get

$$\overline{S} = V_{rms} \angle \alpha \cdot I_{rms} \angle -\beta = V_{rms}\, I_{rms} \cos(\alpha - \beta) + j\, V_{rms}\, I_{rms} \sin(\alpha - \beta). \tag{2}$$

Since

$$P = V_{rms}\, I_{rms} \cos(\alpha - \beta) = \text{Real power, and}$$

$$Q = V_{rms}\, I_{rms} \sin(\alpha - \beta) = \text{Reactive power,}$$

we get

$$\overline{S} = P + jQ\ . \tag{3}$$

COMPONENTS OF A POWER SYSTEM

Components of a power network can be classified into two broad categories: Linear and non-linear components. The linear, passive network consists of transmission lines and transforms; generators and loads are included in the non-linear portion of the network.

Linear Components

Transmission Lines--

Transmission lines can be classified by their length as short, medium, and long lines. Normally, transmission lines are operated with nearly balanced, three-phase loads. Short transmission lines are commonly considered to be lines up to 30 miles long (Neunswander 1971). These lines are usually modeled by a lumped-series impedance (Figure 1). This model is not adequate where the shunt capacitance of the line is important, as with some high-voltage cable circuits. Since in general $X > R$, further approximation is sometimes made by neglecting the restive component in the equivalent circuit where losses are not of major concern, as in short circuit studies and in some long-range transmission-planning studies.

The upper limit on a medium-length transmission line is usually 150 to 200 miles. For power-flow studies, medium-length transmission lines can be modeled by a π-equivalent model (Figure 2, Neunswander 1971). Here Z is the line impedance and Y is the total charging capacitance of the line in admittance form. The medium-length transmission line can also be represented by a nominal T model (Figure 3).

For long lines, a more sophisticated model than the nominal π or T is obtained by considering the line as a distributed-parameter system using incremental line lengths, which results in a more exact representation of the distributed capacitance.

In the π model for a long line (Figure 4), Z_0 is the characteristic impedance of the line and has a value equal to $\sqrt{z/y}$ where z is the impedance per unit length and y is the shunt admittance per unit length of the line. The propagation constant, m, is equal to $\sqrt{zy}$, Y_0 is the characteristic admittance of the line and is equal to $1/Z_0$, and x is the length of the line. An equivalent T model for long lines is shown in Figure 5.

Transformers--

In power-flow studies transformers are usually represented by an ideal transformer and an equivalent-series impedance, with the exciting current

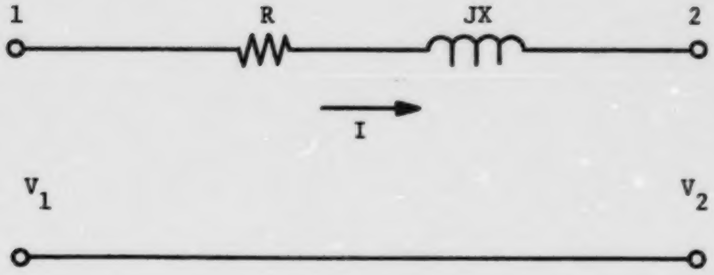

1
R
JX
2
I
V_1
V_2

Figure 1. Equivalent model of a short transmission line.

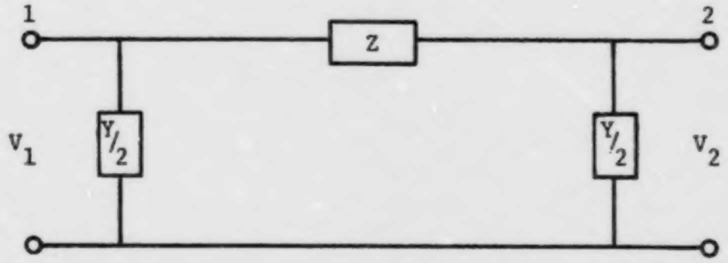

1
2
Z
V_1
Y/2
Y/2
V_2

Figure 2. Equivalent π model of a medium transmission line.

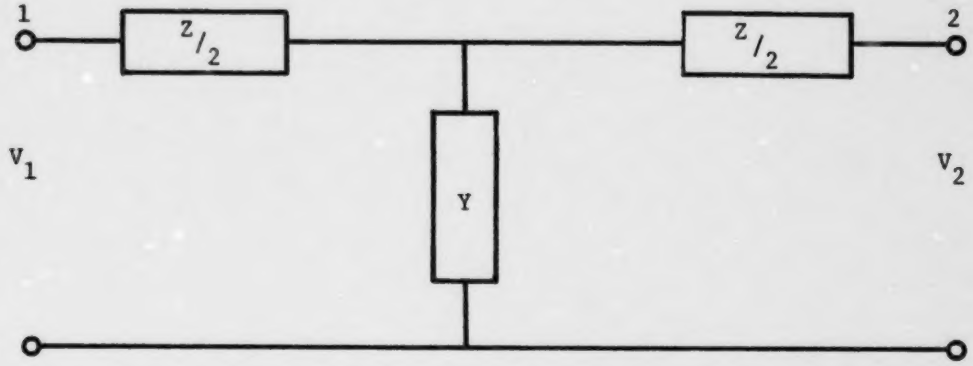

1
Z/2
Z/2
2
V1
Y
V2

Figure 3. Equivalent T model of a medium transmission line.

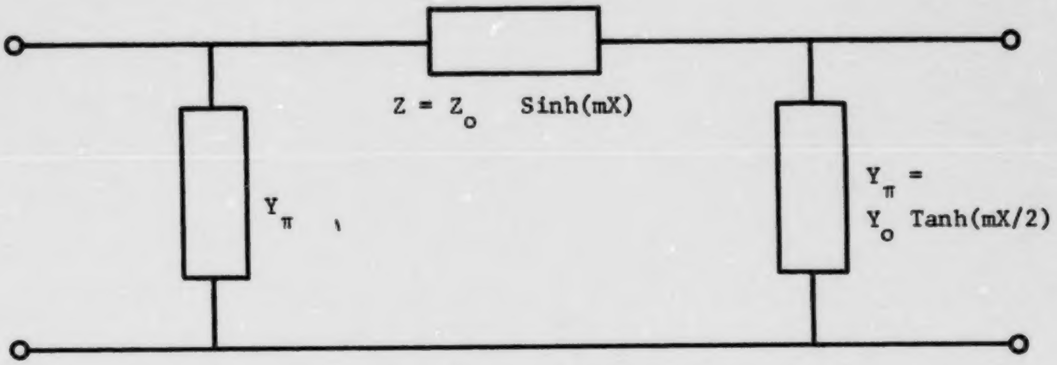

$Z = Z_o \quad Sinh(mX)$
Y_π
$Y_\pi =$
$Y_o \ Tanh(mX/2)$

Figure 4. Equivalent π model of long transmission lines.

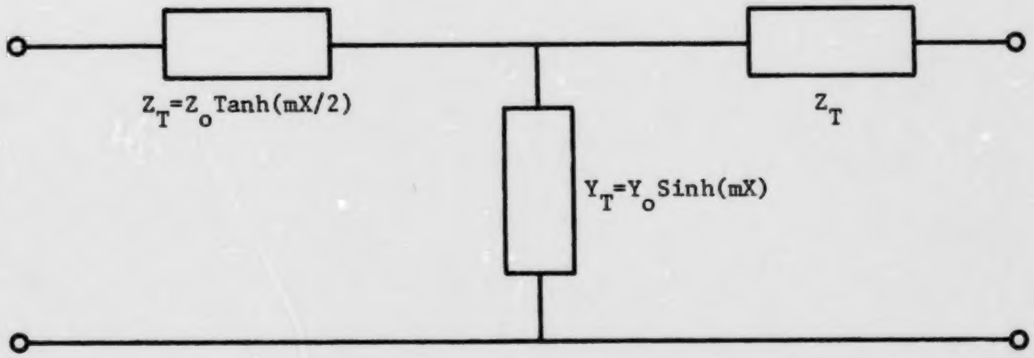

$Z_T = Z_o Tanh(mX/2)$
Z_T
$Y_T = Y_o Sinh(mX)$

Figure 5. Equivalent T model of long transmission lines.

neglected. In the per-unit system, to be discussed later, the transformer with off-nominal turns ratio will be considered as two two-port networks in cascade as shown in Figure 6. With $t = V_2/V_3$, the equivalent π model for this network is shown in Figure 7 (Neunswander 1971). For a transformer with nominal turns ratio, t = 1, this model reduces to a series impedance.

Nonlinear Parts

Generators--

In steady-state, synchronous machines with non-salient rotors are represented by a voltage source in series with an impedance as shown in Figure 8. (For a more detailed treatment of modeling of generators, see Anderson 1977 and Fitzgerald et al. 1971.) For load-flow studies, to be discussed in Section 4, buses are usually divided into three categories: (1) Constant P,Q (non-regulated bus); (2) constant P,V (voltage-regulated); (3) constant V,θ (swing). Generation buses are usually modeled as PV buses with one or more generators modeled as swing or slack buses.

Loads--

For most purposes, loads can be modeled as constant real or reactive powers, constant impedances, or constant current sources. For power-flow studies, load buses are usually modeled by constant real and reactive powers.

NETWORK MATRICES

The first step in any analysis of a power system is the formulation of a suitable network model. In addition to describing the characteristics of individual components in the system, the model should indicate the manner in which the system is interconnected. For computer applications, network matrices are used as an accurate and convenient model for the system.

Selection of independent variables--voltage or current--determines the frame of reference--bus or loop. For present-day network studies, the bus frame of reference is more widely used, and is the frame of reference used in this report.

Primitive Impedance and Admittance Matrices

Primitive matrices indicate the characteristics of the individual primitive impedance matrix, $[Z_{prim}]$, a matrix whose elements are:

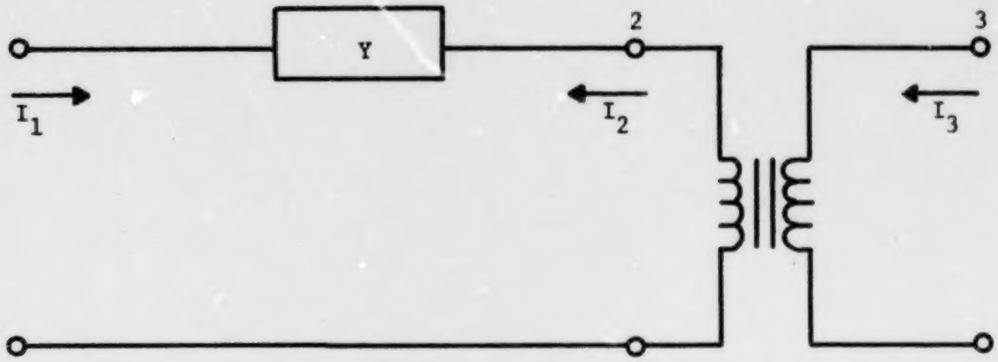


Figure 6. Circuit model of a transformer.

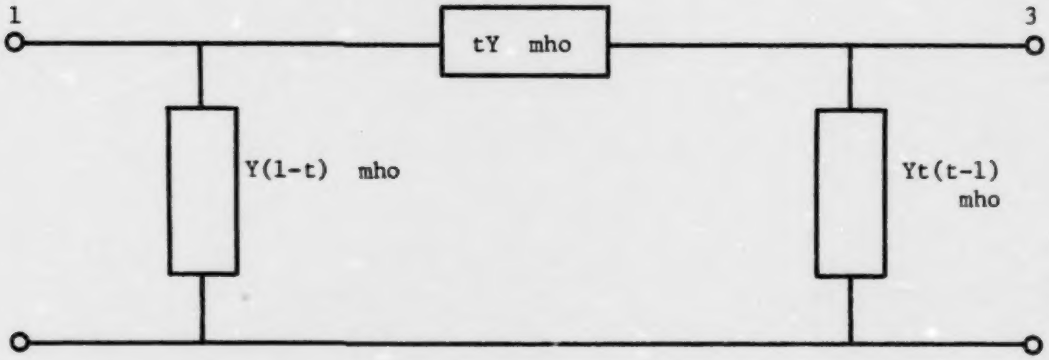

1
3
tY mho
Y(1-t) mho
Yt(t-1) mho

Figure 7. Equivalent π model for transformers.

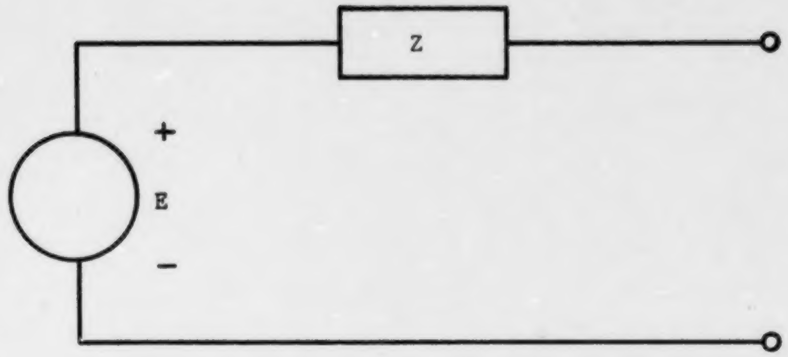


Figure 8. Equivalent circuit for a synchronous machine with a non-salient pole rotor.

Z_{ii} = self impedance of element i, and

Z_{ij} = mutual impedance between elements i and j.

Primitive admittance matrix, $[Y_{prim}]$, is the inverse of the primitive impedance matrix. For practical systems, these primitive matrices are sparse, and in the absence of mutual couplings they are diagonal.

Incidence Matrices

Incidence matrices show the manner in which the system is interconnected. In the bus frame of reference the element-node incidence matrix, A, is used to show the incidence of elements to nodes. The elements of this matrix (Stagg and El-Abiad 1968) are:

a_{ij} = 1 if the ith element is incident to and oriented away from the jth node,

a_{ij} = -1 if the ith element is incident to and oriented toward the jth node, and

a_{ij} = 0 if the ith element is not incident to the jth node.

As an example consider the circuit in Figure 9. The element-node incidence matrix for this circuit (Stagg and El-Abiad 1968) is:

$$\hat{A} = \begin{array}{c|ccccc} e \backslash n & 0 & 1 & 2 & 3 & 4 \\ \hline 1 & 1 & -1 & & & \\ 2 & 1 & & -1 & & \\ 3 & 1 & & & & -1 \\ 4 & & & & -1 & 1 \\ 5 & & & 1 & -1 & \\ 6 & & 1 & -1 & & \\ 7 & & & 1 & & -1 \end{array}$$

If one of the buses is taken as reference and the corresponding column is deleted from the element-node incidence matrix, then a matrix called the bus incidence matrix, A, is obtained.

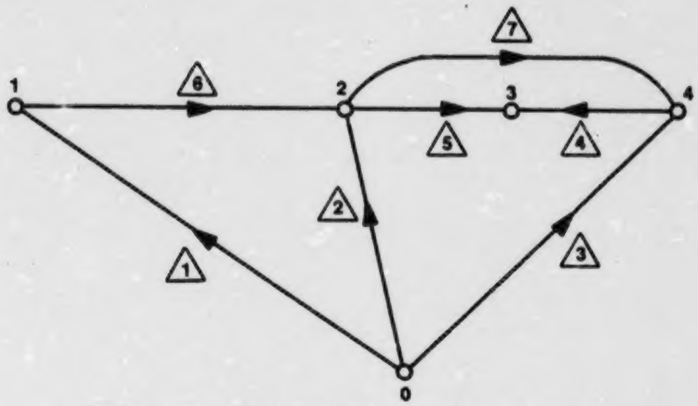

1
2
3
4
0
6
7
5
4
2
1
3

Figure 9. Flow graph of the network.

Bus Impedance and Admittance Matrices

In the bus frame of reference for a system containing n nodes, n-1 independent equations determine the performance of network. In impedance form using matrix notation, this equation (Stagg and El-Abiad 1968) is given as:

$$\overline{E}_{BUS} = [Z_{BUS}]\overline{I}_{BUS} , \tag{4}$$

and in admittance form the equation is given as

$$\overline{I}_{BUS} = [Y_{BUS}]\overline{E}_{BUS} , \tag{5}$$

where $\overline{E}_{BUS}$ = vector of bus voltages, $\overline{I}_{BUS}$ = vector of injected bus currents, $[Z_{BUS}]$ = bus impedance matrix, and $[Y_{BUS}]$ = bus admittance matrix. The bus admittance matrix, $[Y_{BUS}]$, can be found by using the bus incidence matrix and the primitive admittance matrix

$$[Y_{BUS}] = A^t[Y_{PRIM}]A . \tag{6}$$

For cases with no mutual coupling between elements, Y_{BUS} can be found directly by inspection as:

Y_{ii} = sum of the admittances between bus i and all other buses, and

Y_{ij} = -sum of admittances between buses i and j.

The bus impedance matrix can be found by inverting $[Y_{BUS}]$, or it can be developed one step at a time. In this technique the Z_{BUS} for a single element is formed and is modified when branches are added and new buses are formed. This procedure is repeated until the complete network is formed. (For details see Neunswander 1971.)

THE ONE-LINE DIAGRAM

A single-circuit three-phase transmission line consists of three parallel conductors, a neutral conductor if present, and an earth path. Balanced three-phase systems are modeled using symmetrical components, as in a single-phase circuit consisting of one conductor and a return. The result is a so-called one-line diagram. Since varying information is needed for different studies, the one-line diagram takes different shapes for different purposes. For example, for load-flow studies the information on location of circuit breakers is not needed, and therefore one-line diagrams for such studies may not indicate the position of circuit breakers. A typical one-line diagram for load-flow studies is shown in Figure 10.

PER-UNIT REPRESENTATION OF QUANTITIES IN POWER SYSTEMS

In power systems preference is given to expressing voltages, currents, impedances, and powers in per-unit values referred to chosen base quantities rather than in volts, amperes, watts, or vars. Because of the relation of various quantities to one another, selection of any two base quantities determines the base values of the remaining quantities. Usually, base volt-amperes and base voltage are selected. The following equations show the interdependence of base quantities (Stevenson 1975):

$$\text{Base current, A} = \frac{\text{base KVA}_{1\phi}}{\text{base voltage, kV}_{LN}} \tag{7}$$

$$\text{Base impedance} = \frac{\text{base voltage, V}_{LN}}{\text{base current, A}} \tag{8}$$

$$\text{Base impedance} = \frac{(\text{base voltage, KV}_{LN})^2}{\text{base MVA}_{1\phi}} \tag{9}$$

$$\text{Base power MW}_{1\phi} = \text{base MVA}_{1\phi}\ .$$

If base values for line-to-line voltages and three-phase power are used instead of base voltage for line-to-neutral voltages and base power for single-phase power, the above relationships reduce to:

$$\text{Base current, A} = \frac{\text{base KVA}_{3\phi}}{\sqrt{3} \times \text{base voltage KV}_{LL}} \tag{10}$$

$$\text{Base impedance} = \frac{(\text{base voltage, KV}_{LL})^2}{\text{base MVA}_{3\phi}}\ . \tag{11}$$

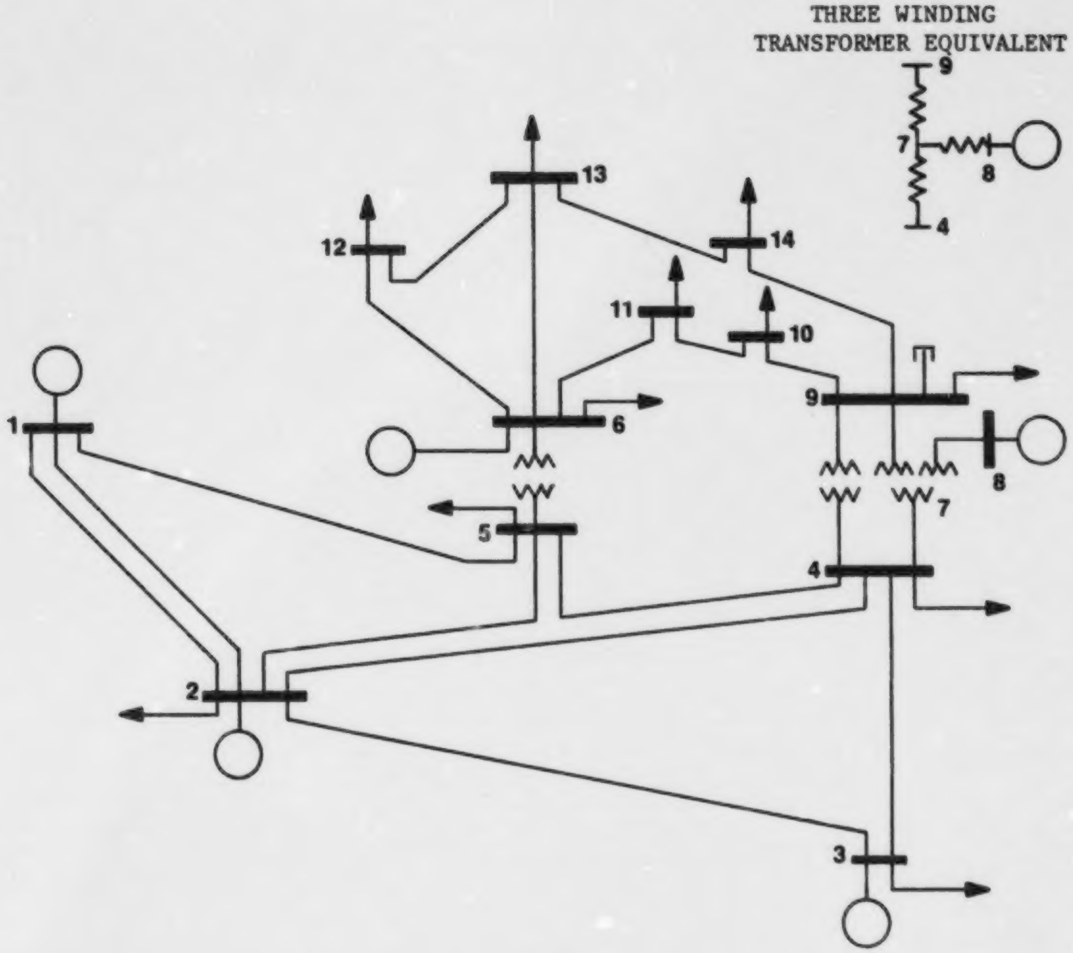

THREE WINDING
TRANSFORMER EQUIVALENT
9
7
8
4
13
12
14
11
10
1
6
9
8
5
7
4
2
3

Figure 10. One-line diagram of the IEEE 14 Bus Test System.

To convert per-unit values of impedance given in one base to per-unit impedance in another base, the following relationship is used (Stevenson 1975):

$$Z_{p.u.\ new} = Z_{p.u.\ old} \quad \frac{\text{base KV}_{old}}{\text{base KV}_{new}}^{2} \quad \frac{\text{base KVA}_{new}}{\text{base KVA}_{old}} \ . \qquad (12)$$

SECTION 4

POWER-FLOW STUDIES

INTRODUCTION

Power-flow or load-flow calculations are performed in many phases of power-system studies such as system planning, operation, and control. Before the advent of digitial computers, the power-flow solutions were obtained using the AC-network analyzers. Network analyzers, also called network calculators and calculating boards, directly simulated the network on a smaller scale using resistances, inductances, and capacitances interconnected to simulate one phase of the actual system. Now digital computers have replaced the network analyzers.

The load-flow problem consists of solving a set of non-linear equations describing the steady-state performance of the system. The principal information obtained from a load-flow solution is the magnitude and phase angle of the voltage at each bus and the real and reactive power flowing in each line.

The methods for determining load-flow can be classified into two broad categories: Z-bus and Y-bus methods. The main advantage of Y-bus methods is that since Y-bus is usually very sparse, the computer memory requirement for Y-bus methods is much less than methods using Z-bus and therefore larger systems can be handled.

In this section the more commonly used Y-bus methods will be considered. An extensive review of the techniques for the solution of the AC power-flow problem is given in Stott (1974).

NETWORK EQUATIONS

Four quantities are associated with each bus. These variables are the real and reactive powers, the voltage magnitude, and the voltage phase angle. Buses are classified into three types (Elgerd 1971). Type 1, the load bus, is also known as the P,Q bus. For this bus, the real and reactive powers are specified. (These may be actual loads or generators with specified P and Q generators.) Type 2, the generation bus, is also known as the P,V or voltage-control bus. For this bus the real power and voltage magnitudes are specified. Type 3, also known as the slack, swing, or reference bus, has specified voltage magnitude and phase angle. Since the losses in transmission lines are not known *a priori*, the real and reactive power at the slack bus are left unspecified to take up the slack in losses (Stagg and El-Abiad 1978). This corresponds to the regulating generator in the operation of a power system.

Four practical limits are set on the state and control variables (Elgerd 1971): (1) Limits on voltage magnitudes; (2) limits on phase-angle differences to constrain the power flow within the rating of the line between buses; (3) real and reactive power limits of generators; (4) thermal limits of lines and transformers. Galiana (1977) discusses in detail these limits and their incorporation into load-flow solutions.

In this bus frame of reference, the relationship between the bus-injected current and bus-to-reference voltage is given by the linear equation

$$\overline{I} = [Y_{BUS}]\ \overline{V} \qquad (13)$$

where I = vector of injected bus currents, $[Y_{BUS}]$ = bus admittance matrix Y_{BUS}, and $\overline{V}$ = vector of bus voltages. The complex power is given as

$$S = P + jQ = VI^* \qquad (14)$$

or

$$S^* = P - jQ = V^*I\ . \qquad (15)$$

Combining Eq. (13) and Eq. (15), the following equation in component form is obtained

$$\frac{P_i - jQ_i}{V_i^*} = y_{i1}V_1 + y_{i2}V_2 + \dots + y_{in}V_n \qquad (16)$$

$$i = 1,\ 2,\ \dots,\ n$$

or

$$P_i - jQ_i = y_{i1}V_1V_i^* + y_{i2}V_2V_i^* + \dots\ y_{in}V_nV_i^*\ . \qquad (17)$$

These complex equations can be decomposed into real equations. In shorthand form, these equations become

$$P_i = \underset{j}{\text{Real}}\ (V_i^* \sum y_{ij}V_j)\ , \text{ and} \qquad (18)$$

$$Q_i = -\text{Im}\ (V_i^* \sum_j y_{ij}V_j)\ . \qquad (19)$$

In polar form we can define

$$V_i \triangleq |V_i|\, e^{j\delta i} \;, \tag{20}$$

and then defining the element y_{ij} of the $[Y_{BUS}]$ as:

$$y_{ij} = G_{ij} + j\, B_{ij} \;, \tag{21}$$

Eq. (18) and Eq. (19) become:

$$P_i = \sum_j \left(|v_i||\, v_j| G_{ij} \cos(\delta_j - \delta_i) - |V_i||V_j| B_{ij} \sin(\delta_j - \delta_i)\right), \text{ and} \tag{22}$$

$$Q_i = -\left[\, \sum_j (|V_i||V_j| B_{ij} \cos(\delta_j - \delta_i) = |V_i||V_j| G_{ij} \sin(\delta_j - \delta_i))\right]. \tag{23}$$

System variables can be divided into the following groups: (1) State variables, $\overline{x}$, including voltage phase angles at P,V buses, and voltage-magnitude and phase angles at P,Q buses; (2) control variables, $\overline{U}$, including voltage magnitude and phase angle at the swing bus and real power at P,V buses; (3) uncontrollable or disturbance variables, $\overline{D}$, which include the real and reactive powers at the P,Q buses. In terms of the variables defined, Eq. (22) and Eq. (23) can be written in matrix form (Sullivan 1977):

$$\overline{f}(\overline{x},\overline{u},\overline{D}) = \overline{0} \;. \tag{24}$$

In more concise forms, Eq. (24) can be written as

$$\overline{f}(\overline{x},\overline{u}) = \overline{0} \;, \tag{25}$$

or simply

$$\overline{f}(\overline{x}) = \overline{0} \;. \tag{26}$$

SOLUTION METHODS

Of the techniques to solve Eq. (26), the Gauss iterative method and the Newton-Raphson technique are discussed. In addition, particular attention will be given to the fast-decoupled technique and to DC load-flow techniques since these two load-flow techniques are employed in the network-expansion algorithm. For a detailed discussion of different load-flow solution methods, see Stott (1974).

The Gauss Iterative Method

In Gauss' method, Eq. (26) is rewritten as:

$$\bar{x} = \bar{F}(\bar{x}) \ . \tag{27}$$

An arbitrary guess for the values of the variable $\bar{x}$ is then made. Based on this initial guess, Eq. (27) is solved, and new values for the variables are obtained. The procedure is repeated, this time with the new values for the variable $\bar{x}$. This method is continued until satisfactory convergence is obtained or the process diverges. In a variation of Gauss' iterative method, called the Gauss-Seidel method, individual variables are updated as soon as they become available. The main disadvantage of the Gauss or the Gauss-Seidel methods is their slow-convergence properties.

The Newton-Raphson Method

The Newton-Raphson method is one of the most sophisticated methods for solving a set of simultaneous nonlinear equations of the form given by Eq. (26). This method is based on the Taylor-series expansion of the equations. At a given iteration point each function is approximated by its first-order derivatives. The basic steps for this technique are as follows.

First, for the system of equations represented by Eq. (26), an initial values for the state variables is assumed, $\bar{x}^i$, where i denotes the iteration number; in this case i = 0 to indicate the starting value. Second, the values of x^i thus found is replaced in Eq. (26), and an error vector is found:

$$\bar{\varepsilon}^i = \bar{f}(\bar{x}^i) \ . \tag{28}$$

Third, the derivative of $\bar{f}(\bar{x})$ with respect to $\bar{x}$, called the Jacobian matrix whose elements are the partial derivative of functions $f_1, \ldots, f_n$ with respect to the variables $x_1, \ldots, x_n$, is calculated at the value of $\bar{x}^i$

$$\bar{f}_x^i = \left. \frac{d\bar{f}(\bar{x})}{d\bar{x}} \right|_{\bar{x}=\bar{x}^i} \ . \tag{29}$$

Fourth, the correction, $\Delta\bar{x}^{i}$, is calculated from the following equation:

$$\bar{f}_{x}^{i}\,\Delta\bar{x}^{i} = -\bar{\varepsilon}^{i} \ . \tag{30}$$

Fifth, new values of the state vector $\bar{x}$ are found from this equation:

$$\bar{x}^{i+1} = \bar{x}^{i} + \Delta\bar{x}^{i} \ . \tag{31}$$

Sixth, steps 2 through 5 are repeated until satisfactory convergence is obtained.

Several observations are in order. The Jacobian matrix, $\bar{f}_x$, is a square matrix with elements as shown below:

$$\bar{f}_x = \begin{matrix} \frac{\partial f_1}{\partial x_1} & \frac{\partial f_1}{\partial x_2} & \cdots & \frac{\partial f_1}{\partial x_n} \\ \vdots & & & \\ \frac{\partial f_n}{\partial x_1} & \frac{\partial f_n}{\partial x_2} & \cdots & \frac{\partial f_n}{\partial x_n} \end{matrix} \ . \tag{32}$$

In power-flow studies, the Jacobian matrix is sparse and in block form has the same topology as the model admittance matrix $[Y_{BUS}]$. Solution of Eq. (30) calls for inverting this matrix which may result in a full matrix. In early attempts to implement the Newton-Raphson technique in the solution of the load-flow problem, the main difficulty was the requirements for computer time and memory (Tinney and Hart 1967). This problem can be overcome by the employment of sparse-matrix techniques and the "optimally ordered elimination" procedure (Sato and Tinney 1963, Tinney and Hart 1967).

An advantage of the Newton-Raphson power-flow solution method over the Gaussian method is its faster convergence. In the former, the number of iterations for convergence to a solution is independent of the size of the system under study, and convergence is usually obtained in four to six iterations.

Several modifications to the basic Newton-Raphson method can be made. The same Jacobian matrix can be used, without recomputing, for several successive iterations. This step significantly reduces computing time. The fast-decoupled load-flow method (Stott and Alsac 1974), discussed in the next section, takes advantage of the weak coupling between voltage magnitudes and real powers and between voltage phase angles and reactive powers.

Of the different versions of the Newton-Raphson load-flow method in use, the polar-power-mismatch version is the most widely used (Stott 1974). In this form, the Jacobian matrix equation, Eq. (30), is composed of blocks in the following form:

$$\begin{bmatrix} \Delta P \\ \hline \Delta Q \end{bmatrix} = \left[\begin{array}{c|c} H & N \\ \hline J & L \end{array}\right] \begin{bmatrix} \Delta\theta \\ \hline \frac{\Delta V}{V} \end{bmatrix} . \qquad (33)$$

The polar-power-mismatch version usually converges satisfactorily in two to five iterations from a flat start of $v = 1$ p.u. and $\theta = 0$ (Stott 1974).

The Fast-Decoupled Method

A variation of the Newton-Raphson method, called the fast-decoupled method, takes advantage of the weak coupling between voltage magnitudes and real powers and between voltage phase angles and reactive powers. Furthermore, the Jacobian matrix is approximated by a constant matrix. Since this technique is employed in the network-expansion algorithm developed in this report, a fairly detailed description of this method is given. For further discussion of this method, see Stott and Alsac (1974).

Because of decoupling, N and J in Eq. (33) are much smaller than H and L. Therefore, an approximation is made by setting N and J equal to zero, which reduces Eq. (33) to two equations:

$$[\Delta P] = [H]\ [\Delta\theta] \text{ , and} \qquad (34)$$

$$[\Delta Q] = [L]\ [\Delta V/V] \text{ .} \qquad (35)$$

The elements of the [H] and [L] matrices are

$$H_{km} = L_{km} = V_k V_m (G_{km} \sin\theta_{km} - B_{km} \cos\theta_{km}) \qquad (36)$$

for $m \neq k$ and

$$H_{kk} = -B_{kk} V_k^2 - Q_k ,\quad L_{kk} = -B_{kk} V_k^2 + Q_k , \qquad (37)$$

where θ_k, V_k = voltage angle, magnitude at bus k, $\theta_{km} = \theta_k - \theta_m$, and $G_{km} + jB_{km}$ = (k,m)th element of the bus-admittance matrix. Further simplification can be made by letting $\cos\theta_{km} \cong 1$, $G_{km} \sin\theta_{km} \quad B_{km}$, and $Q_k < B_{kk} V_k^2$.

With these assmptions, Eq. (36) and Eq. (37) reduce to

$$H_{km} = L_{km} = - V_k V_m B_{km} \text{, and} \qquad (38)$$

$$H_{kk} = L_{kk} = - B_{kk} V_k^2 . \qquad (39)$$

Eq. (38) and Eq. (39) then reduce to

$$[\Delta P] = [V \cdot B' \cdot V] [\Delta\theta] \text{, and} \qquad (40)$$

$$[\Delta Q] = [V \cdot B'' \cdot V] [\Delta V/V] \text{ ,} \qquad (41)$$

Where elements of B' and B" matrices are elements of [-B], the imaginary part of the bus-admittance matrix.

Four steps further simplify the method: (1) Shunt reactances and off-nominal transforms are omitted in B'; (2) phase shifters are omitted from B"; (3) in Eq. (40) the right-hand side V terms are set to 1 p.u.; (4) series resistances are neglected in calculating elements of B'. With these modifications, Eq. (40) and Eq. (41) are rewritten as:

$$[\Delta P/V] = [B'] [\Delta\theta] \text{, and} \qquad (42)$$

$$[\Delta Q/V] = [B''] [\Delta V] \text{ .} \qquad (43)$$

Matrices B' and B" are real, sparse, and, in the absence of network changes, constant. During the successive iterations, these matrices are factored once, and vectors [Δθ] and [ΔV] are obtained by forward eliminations and back substitutions in the process of calculating them by the Gaussian elimination procedure. The fast-decoupled load-flow method usually converges in four to seven iterations, each iteration being five times as fast as that of a Newton-Raphson iteration (Stott and Alsac 1974).

The DC Power Flow

Direct-current power flow, which can be considered as one iteration of the fast-decoupled load flow on real powers, is probably the most widely used power-flow model in the literature on automated transmission-system planning. Transmission system planning techniques based on the use of DC power flows, however, have not been used much by utility planning engineers. In this model, only the active power flows are considered. The model takes the following form:

$$P_{Gi} - P_{Li} = \sum_{j=1}^{N} B_{ij}(\delta_i - \delta_j) \qquad i=1, \ldots, N , \qquad (44)$$

where P_{Gi} = the active power generated at bus i, P_{Li} = the active power consumed at bus i, B_{ij} = the susceptance of the line connected between buses i and j, and δ_i = the voltage phase angle at bus i. These equations are linear and they can be solved by non-iterative techniques.

SECTION 5

NETWORK EQUIVALENTS

In planning transmission-line networks, the system is often studied in simplified form or attention is focused on only a portion of the system. Since changes in one portion of the network may have a small interaction with other portions of the system, non-essential portions of the network may often be replaced by simple equivalents. This technique may allow the planner to focus on those parts of the network that are of interest, which would reduce computer time, cost, memory requirements, and programming complexity.

Network-reduction techniques range from very crude techniques, such as representing each geographic area by one bus whose variables are the average of those in the area, to sophisticated techniques using Taylor-series expansions. The most widely used method is the classical node-elimination method, also known as the Ward-Hale method. A second method, which was developed in the early 1960's and received little attention until recently, is the radial equivalent independent (REI) method. Still a third technique, the linearized-reduction method, is the most exact of the three. This technique was developed by Fernando Alvarado and Elsayed Elkonyaly.

CLASSICAL REDUCTION

This method was developed by Ward (1949). Loads and generators within the portion of the system to be reduced are approximated by constant impedances and/or constant-current sources. Using the bus admittance matrix, the network is modeled as

$$\overline{I} = [Y_{BUS}]E \ . \tag{45}$$

Assuming that a network containing n buses is to be reduced to a network of size m, the above equation can be reordered so that the first n-m elements of $\overline{I}$ and $\overline{E}$ vectors correspond to the buses to be eliminated. In this configuration, Eq. (45) can be rewritten in the partitioned form as

$$\begin{bmatrix} I_1 \\ \hline I_2 \end{bmatrix} = \left[\begin{array}{c|c} Y_{11} & Y_{12} \\ \hline Y_{21} & Y_{22} \end{array}\right] \begin{bmatrix} E_1 \\ \hline E_2 \end{bmatrix} . \tag{46}$$

Equation (46) can be expanded in the following form:

$$I_1 = y_{11}E_1 + y_{12}E_2 \text{ , and} \tag{47}$$

$$I_2 = y_{21}E_1 + y_{22}E_2 \text{ .} \tag{48}$$

Assuming that y_{11}, y_{12}, y_{21}, y_{22}, and I_1 are known and constant, E_1, can be calculated from Eq. (47):

$$E_1 = y_{11}^{-1} I_1 - y_{11}^{-1} y_{12} E_2 \text{ .} \tag{49}$$

The expression for E_1 is substituted in Eq. (48):

$$I_2 = (y_{22} - y_{21} y_{11}^{-1} y_{12})E_2 + y_{21} y_{11}^{-1} I_1 \text{ .} \tag{50}$$

Let

$$Y'_{22} = y_{22} - y_{21} y_{11}^{-1} y_{12} \tag{51}$$

and

$$I'_2 = I_2 - y_{21} y_{11}^{-1} I_1 \text{ .} \tag{52}$$

Then from Eq. (50):

$$I'_2 = Y'_{22} E_2 \text{ .} \tag{53}$$

This equation model's the resulting network.

RADIAL EQUIVALENT INDEPENDENT (REI) METHOD

This technique was developed in the early 1960's by Dimo (1975), but only recently did it receive much attention. In the REI approach the identity of generators in the reduced portion of the network are preserved by representing them by an equivalent generator that is retained.

The REI approach has four basic steps (Figure 11). First, a load-flow solution for the base case for the entire system is obtained. Second, using the base-case load-flow results, the generators in the portion of the system to be reduced are represented by equivalent-constant admittances between the original nodes and a fictitious intermediate node, G. An arbitrary value of voltage V_G can be assigned to this node, and the equivalent constant admittances are found from this equation:

$$Y_i = \frac{I_i}{V_G - V_i} , \tag{54}$$

where Y_i = the equivalent admittance in the ith branch, V_G = voltage at bus G., and I_i = current injection at node i (calculated from base-case power flow). Dimo always let $V_G = 0$.

Third, an equivalent generator, whose net power generation, S_R, is equal to the sum of the power generations of the eliminated generators, is connected to the intermediate node, G, through an equivalent admittance, Y_R. This equivalent admittance is chosen to offset the additional power loss by all other equivalent admittances, according to the following equation:

$$Y_R = \frac{I_R}{V_R - V_G} . \tag{55}$$

The voltage, V_R, is found from

$$V_R = \frac{S_R}{I_R^*} . \tag{56}$$

Fourth, while retaining the equivalent generator, the resulting network is then reduced using the classical reduction method.

An extension of the REI approach was recently introduced (Dy Liacco et al. 1978). In this method, called the X-REI, the nodes in the portion of the network to be reduced are classified as essential or non-essential nodes. The selection of essential nodes is either heuristic or based on sensitivity matrices, an essential node being any node at which a change in injection would have a significant effect on the state of a boundary node. The REI reduction procedure is carried out on all essential nodes.

For more detailed descriptions of the REI reduction method, see Dimo (1975), Alvarado and Elkonyaly (1977), Elkonyaly (1977), and Tinney and Powell (1977).

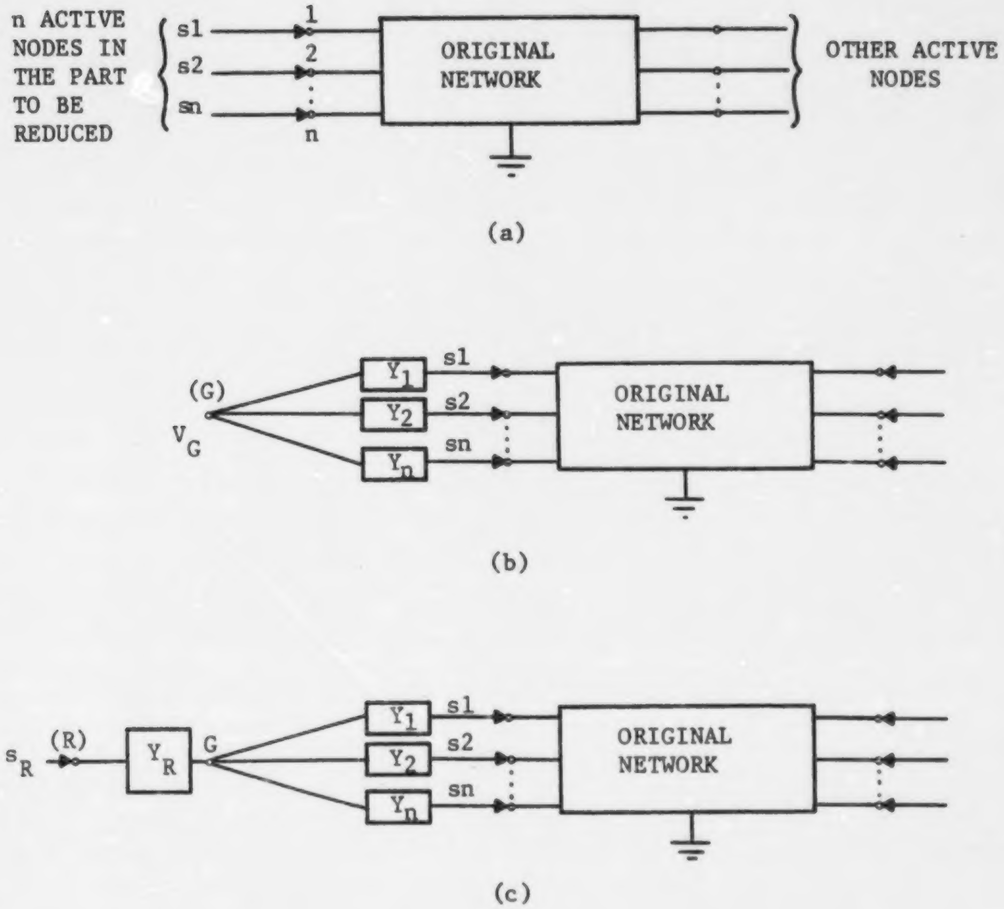

n ACTIVE NODES IN THE PART TO BE REDUCED
s1
s2
sn
1
2
n
ORIGINAL NETWORK
OTHER ACTIVE NODES
(a)
(G)
V_G
Y_1
Y_2
Y_n
s1
s2
sn
ORIGINAL NETWORK
(b)
s_R
(R)
Y_R
G
Y_1
Y_2
Y_n
s1
s2
sn
ORIGINAL NETWORK
(c)

Figure 11. REI equivalent.

(a) Original network.
(b) Generators are replaced by equivalent admittances between the intermediate node, G, and terminal buses.
(c) An equivalent generator is added where $S_R = S_1 + S_2 + \dots + S_n$ with an equivalent admittance Y_R.

LINEARIZED-REDUCTION METHOD

The linearized-reduction procedure was developed recently by Alvarado and Elkonyaly (1977) and Elkonyaly (1977). In this method the network is divided into two subnetworks (Figure 12). The reduced network is represented at the boundary buses by a constant injection (the base-case solution) in parallel with a variable injection which is linearly dependent on voltage-magnitude deviation and phase-angle deviations from the base case. The variable injections can be considered to be produced by constant "pseudo admittances" (Elkonyaly 1977).

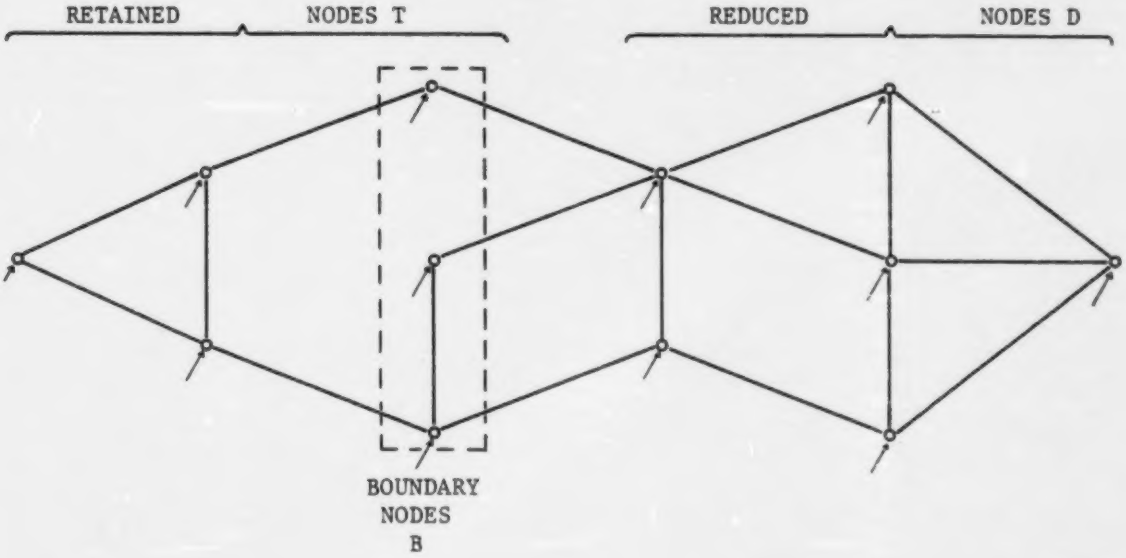


Figure 12. Classification of buses for reduction.

The complex injection at boundary buses can be approximated by a first-order Taylor series as

$$\bar{S}_B = \bar{S}^o_B + \frac{d\bar{S}_B}{d\bar{V}_B}\left(\bar{V}_B - \bar{V}^o_B\right) , \qquad (57)$$

$$\frac{d\bar{S}_B}{d\bar{V}_B} = \frac{\bar{S}_B}{\bar{V}_B} + \frac{\bar{S}_B}{\bar{V}_D} \times \frac{d\bar{V}_D}{d\bar{V}_B} , \qquad (58)$$

where $\bar{S}_B$ = vector of injections at boundary buses, $\bar{S}^o_B$ = vector of base-case injections at boundary buses, $\bar{V}_B$ = complex voltages at boundary buses, and $\bar{V}_D$ = complex voltages within the reduced part. Equations (57) and (58) are complex equations, each of which can be divided into two real equations. The derivative terms in Eq. (57) are considered as pseudo admittances, which simulate the variations caused by changes in the state of the reduced portion of the network. For details of the procedure to find these admittances see Alvarado and Elkonyaly (1977) and Elkonyaly (1977).

MODIFIED CLASSICAL REDUCTION

Since the Ward-Hale method may result in poor equivalents caused by improper selection of boundary buses, Monticelli et al. (1978) present a simple extension of the Ward-Hale method. This technique increases the accuracy of the model, especially for outage studies. To each boundary bus, i, of the load type (or the PQ type), a new fictitious PV bus, m, with $P_m = 0$ and $V_m = V_i$, is attached by means of fictitious branches with admittance $\hat{Y}_i$.

SECTION 6

REVIEW OF PRESENT NETWORK-PLANNING TECHNIQUES

The process of planning for the expansion of a power system starts with a forecast of future loads. These forecasts are used to determine the capacity of additions to generation, transmission, and, later, distribution systems. Studies of power-system planning can be divided into four types: load forecasting, generation planning, transmission-network planning, and distribution-network planning.

Transmission-network planning can be classified according to the length of the study period as short-range, intermediate-range, and long-range (Fischl 1975). Short-range problems can be carried out with considerable detail. Long-range studies are, on the other hand, carried out with less detail because of the complexity of the problem and the uncertainty of forecasts of load and geographic variations in loads.

Planning problems have traditionally been treated as mathematical-optimization problems, and various optimization techniques have been employed. These techniques include heuristic methods, linear programming, nonlinear programming, dynamic programming, and integer programming.

Despite many attempts to apply these methods to transmission-network problems, no practical solution has been found. This failure may be caused by a large number of variables that cannot easily be quantified and are difficult to predict, such as costs and environmental, political, geographical and technical constraints.

In this section a review of optimization methods is followed by a discussion of present network-expansion techniques.

MATHEMATICAL MODELS OF TRANSMISSION SYSTEMS

To carry out optimization studies, the first step is to model the system. The model must satisfy two conflicting requirements: (1) It must be realistic and accurate enough to provide meaningful results, but (2) it must not be so complicated that the costs involved in evaluating alternatives and strategies outweigh the returns achieved by the use of the model (Ringlee and Wollenberg 1976).

Although the alternating-current load-flow model given by Eq. (22) and Eq. (23) is a very accurate model for a power network, such accurate power-flow models have seldom been used in automated-planning studies. The primary reason for this is that a large number of contingency tests are usually carried out in planning studies, and a relatively large amount of computing time is required for the convergence of AC load flow. Furthermore, since the data on which the planning studies are dependent--the future load profile--cannot be predicted easily and accurately, the use of such an accurate model is not justified if simpler models are available that are more amenable to computer studies and whose results are useful.

The power-flow model most often used in theoretical literature on planning studies is the DC load-flow model [Eq. (44)]. In studies using the DC load flow, the design parameters are B_{ij}, the series susceptance of lines. The fast-decoupled load flow is accurate and fast, but, since it is relatively new, it has only been incorporated in conjuction with one planning method (Sjelvgren and Bubenko 1977).

FORMULATION OF PROBLEM

Once a mathematical model for the system is obtained, the next step is to state the expansion problem as a mathematical-optimization problem: optimizing a performance index or cost function subject to a set of equality and/or inequality constraints. The performance index or the cost function that is minimized is usually chosen as a function of capital costs and operating costs. Capital costs include equipment, depreciation, and removal. If the existing equipment is to be removed and retired early, the cost coefficients should reflect the removal costs incurred.

Transmission planning is usually done for balanced steady-state operation of the system, but also for considering many outage contingencies. The model of the system itself constitutes one set of the equality constraints. Other constraints may include generator VAR limits, thermal and stability limits on transmission-system elements, and operation of the system under line outages and generator outages. Studies of transient and dynamic stability for the system are usually not carried out at this stage because of the extensive computer time required. These studies are only carried out for the alternative designs of the final candidates for transmission and generation systems.

METHODS OF OPTIMIZATION

The term optimal solution, so widely used in the literature, is misleading. The optimal solution depends on the system model, the particular performance index chosen, and the optimization technique. The optimal solution obtained for a particular performance index may be different from that obtained using another performance index designed for the same purpose. Furthermore, the same system can be represented by a number of different models and, depending on the degrees of approximation incorporated in deriving these models, the so-called optimal solutions may vary.

Present network-planning techniques differ basically in the optimization techniques that they employ. Optimization techniques can be classified as logical or mathematical-function approaches (Ringlee and Wollenberg 1976), or in other words as direct or indirect methods. Direct methods are those in which the values of the objective functions for alternative solutions are compared and the design parameters that optimize the objective function are found. With indirect methods, solutions are sought for which the objective function will not change when infinitesimal changes in the values of variables occur. Indirect methods usually employ linear combinations of constraints and partial derivatives of the objective function.

Search Techniques

Search techniques fall into the category of logical techniques. No restrictions are placed on the type of performance index or the solutions. The major disadvantage of these techniques is the computation requirements as the number of variables and alternatives grow. For example, if there are n variables, each with m possible values, the number of alternatives will be equal to m^n. Search techniques are especially suited for cases where no direct mathematical relationship exists between the independent variables and the objectives.

Gradient methods can be incorporated in search techniques. In many problems where the objective function is an implicit function of several variables, gradient methods are used. In these methods the change at each step of the objective function with respect to the variables indicates improved values for those in the next step. The constraints are usually incorporated in the objective function. Gradient methods can be divided into first- and second-order methods, and each category can be further subdivided. For details see Ringlee and Wollenberg (1976), Cooper and Steinberg (1970), and Lasdon (1970).

Mathematical-Programming Techniques

The term mathematical programming refers to all mathematical methods of optimization. The basic formulation of all mathematical-programming techniques minimizes or maximizes an objective function $f(x_1, \ldots, x_n)$ by a proper choice of the vector $x = (x_1, \ldots, x_n)$. If the variables x_i are allowed to take on any value, then the problem is called an unconstrained-optimization problem. On the other hand, if the variables are restricted to certain allowable values, the problem is called a constrained-optimization problem (Lasdon 1970). Mathematical-programming techniques are further classified according to objective functions, variables, constraints, and methods.

Linear-programming techniques deal with optimization problems in which the objective function is a linear function of the independent variables. The constraints should also be linear functions of the independent variables. The basic computational algorithm for solving linear programming problems, known as the simplex algorithm, was first developed in 1947 by George Dantzig (Dantzig 1963). Discrete or integer linear programming deals with linear-programming problems in which some or all of the variables take on integer values. Branch and bound algorithms are often used with these techniques. Integer bounds are placed on noninteger variables that are supposed to be integers, and successive linear programs are computed. Quadratic programming deals with a class of optimization problems in which the objective function contains quadratic terms and constraints are linear. Quadratic programming can be classified as a special case of nonlinear problems that can be solved by linear-programming methods. Separable programming problems are another special class of nonlinear problems that can be solved by linear-programming methods. In this class of problems the objective function and constraints are nonlinear but separable; that is, the performance index and constraints are functions of powers of variables, but the cross-product terms are absent. In these problems, the functional relationships take the following general form:

$$f(x_1,x_2, \ldots, x_n) = f_1(x_1) + f_2(x_2) + \ldots + f_n(x_n) \; . \qquad (59)$$

Functions of this type are called separable (Gottfried and Weisman 1973) and can be approximated by piecewise linear functions.

Nonlinear programming is applied to problems that contain nonlinear functions. These problems are solved by the indirect methods using the Lagrangian and Kuhn-Tucker multipliers. Another approach for solving nonlinear programming problems is by the direct approach using gradient methods. Detailed solution techniques are given by Mangasarian (1969).

Dynamic programming is based on Bellman's principle of optimality. This technique is suited for multistate optimization problems, such as resource allocation and commitment scheduling. The dynamic-programming formulation becomes computationally unfeasible when the number of variables becomes large.

Variations of all these programming techniques have been developed, and methods exist for specific problems. Standard programming codes using various programming techniques are listed by Kuester and Mize (1973).

PRESENT NETWORK-EXPANSION TECHNIQUES

As mentioned above, the major differences among present network-planning techniques are their optimization methods. Almost all the optimization techniques mentioned in previous sections have been used in one form or another for network-expansion planning.

One of the earliest attempts at computer solutions of network-expansion problems using heuristic techniques was made by De Salvo and Smith (1965).

The system is modeled by the AC load flow. The program also uses economic dispatch, a low-voltage logic, an overload logic, economics, and penalty-factor subroutines. The low-voltage logic program checks each bus voltage for low voltages. Capacitors are added to low-voltage buses to raise the voltage. Different criteria are used in the three different low-voltage logic subprograms. After low voltages have been eliminated, the overload-logic subprogram is run. The overload logic functions in the same manner as the low-voltage logic. A given list of network changes is tried until the overloads are alleviated. Mamandur and Berg (1978) tested a network for overloads and, where overloads were present, the K-shortest loopless paths in the network were found and transmission-line additions along the shortest path were planned. This method provides alternative (suboptimal) expansion plans from the same computer run.

Linear-programming techniques have been used in two formulations. One seeks answers for the minimum cost-capacity additions (Kaltenbach et al. 1970). In this technique the system is modeled by a slightly modified form of DC load flow. Branch susceptances are replaced by a measure of branch capacities. The objective function is a linear function of capital costs and operating costs. Operating costs are mainly the cost of thermal loss of power. The constraints are the ratings of lines. Linear programming is used to find a set of minimum cost-capacity additions. The second formulation seeks the most direct route from generators to loads (Garver 1970). To each path a guide number is assigned. These guide numbers reflect the relative costs of new additions to the circuit, and they are proportional to line lengths. The linear-programming subroutine is used to find the right-of-way with the largest overload and to add lines to it.

Mixed-integer linear-programming techniques are incorporated by Lee et al. (1974) in a program using the DC load-flow model. The DC load-flow equations are solved by triangular factorization. The sensitivity coefficients of angular differences to changes in admittances of all rights-of-way are calculated. A screening algorithm to reject ineffective rights-of-way is used to reduce the dimension. Then an integer program is set up and solved, by branch-and-bound techniques, to obtain a set of line additions.

A recent integer linear-programming formulation integrates the planning problems for generation and transmission into one problem (Sawey and Zinn 1977). This model requires that all potential sites for location of new or expanded power plants and expanding transmission rights-of-way be defined. The objective function to be minimized is the sum of capital and operating costs. The constraints are divided into nine types, including flow limits and generator-installed capacity limits.

A variation of nonlinear programming is the optimization method used by Fischl and Puntel (Fischl and Puntel 1972, Puntel et al. 1973, and Fischl and Schiekle 1976). The main feature of this technique, which uses the DC load-flow model, is an "adjoint power system" to calculate the sensitivities of the performance index with respect to the independent variables. The original system is changed according to the sensitivity of performance index using gradient techniques. A single-contingency reliability criterion is used in this method.

Recently, a quadratic-integer-programming technique was proposed (Sjelvgren and Bubenko 1977). The main features of this technique are the inclusion of second-order sensitivity modeling of changes in branch power flows, a zero-one quadratic-integer program, and a fast-decoupled power-flow model.

Dusonchet and El-Abiad (1973) combined the deterministic search procedures of dynamic programming with a probabilistic-search criterion and heuristic stopping criterion into a discrete-dynamic-optimization procedure, and applied this combination to transmission-network planning. In this procedure a strategy is selected at random and its neighborhood is generated. A neighborhood consists of a limited number of strategies including the original strategy. Dynamic programming is used to find the least expensive strategy. The objective function to be minimized is the present cost of alternative strategies multiplied by a performance-penalty factor that takes on values of 1 or ∞. The system model is a modified DC load-flow model.

The techniques discussed so far have treated the problem as a deterministic problem. Uncertainties have been specified in terms of maximum and minimum values. Therefore, these techniques can be considered as worst-case design techniques. In contrast, stochastic design has been used by Henault et al. (1970). In this technique the only uncertainties considered are future loads. The expected value of a cost function, which includes investment costs, operating costs, and penalty costs, is minimized by dynamic programming subject to a state-transition equation and other constraints. This method can be classified as stochastic-dynamic programming.

In addition to the techniques mentioned and classified according to their solution methods, other network-planning aids should be mentioned. A graphic planning system can be an extremely valuable tool for planning studies (Roman et al. 1976). Using this tool the planner has the opportunity to run numerous on-line, load-flow studies and to study various system configurations.

In summarizing this review, several points should be noted. Network-planning methods that have appeared in the literature are difficult to evaluate and compare because few of them have ever been developed beyond experimental stages. The demonstrational networks that have appeared in conjunction with these methods have all been systems of very limited sizes, and no evidence has been given as to the applicability of these methods to large networks. Another difficulty is that the automated planning techniques available do not include all the complex, interrelated, and often changing political, regulatory, social, esthetic, and environmental factors that influence system planning.

SECTION 7

THE PROPOSED METHOD FOR COMPARATIVE STUDIES OF TRANSMISSION NETWORKS

The transmission network associated with a given generation or load-expansion plan may impose limitations on various generation sites in terms of the amount of power that can be generated or delivered. Therefore, the transmission network plays an important role and should be considered in the process of evaluation and comparison of various generation-expansion plans. For such studies when the network-expansion algorithm is being used only for comparative evaluation of generation sites and not for actual network expansion, simplified, approximate planning methods are needed.

Most of the network-expansion methods treat the problem as a mathematical-optimization problem. One of the standard optimization methods is used, and a so-called optimal expansion plan for the network is obtained. These solutions are not guaranteed to be optimal, however, from an economic and practical viewpoint, since they do not provide the best expansion plan upon which actual investment decisions could be made. In practice no automated network-planning program can produce optimal results. This limitation exists mainly because representations of a network by a mathematical model require the inclusion of several variables that cannot be quantified. For example, when lines of higher voltage are added to a particular right of way, these additions are not usually optimal economically, during the first few years. As a result, such algorithms are neglected by most network-expansion algorithms.

The algorithm for expansion of a transmission network developed in this report uses a simple, logical technique that may closely parallel the logic used by planning engineers. No claim is made that the expansion plans obtained by this algorithm will be optimal, but they will be close to those provided by the planning engineers.

THE BASIC METHOD

In practice network expansion is carried out based on the experience with the network of the utilities' planning engineers. The method developed here follows the same basic steps carried out in practice and uses sensitivity matrices to supplement the planning engineers' experience.

Before a transmission-planning study begins, the sites, sizes, and timing of future additions of generating power will tentatively be planned for the entire period of the study. In addition, the following data are needed: (1) Descriptions of the existing transmission system; (2) forecasted load profiles for the entire planning period; (3) a list of potential rights-of-way, their lengths, constraints, and the particular transmission facilities that they can accomodate; (4) impedances, shunt capacitances, and capacities of available new transmission facilities and their cost data; (5) operating constraints for the system, which are greatly influenced by transmission limitations; (6) legal, environmental, and political constraints; and (7) reliability criteria.

To represent the network two models are used, a DC load-flow model and the fast-decoupled AC load-flow model. The DC model expands the network by checking line over-loads only. The AC model is a more accurate representation of the network and expands the network by accounting for line overloads and deviations in bus-voltage magnitudes.

NETWORK PLANNING

The network-planning algorithm can be divided into three integral parts: Network modeling, contingency analysis, and expansion logic. For the DC model, the expansion logic consists of checking for overloads and expanding the network to remove over-loads. In the AC model, in additon to overload logic, a voltage-correction logic is included. The contingency analysis and the expansion logics are based on a sensitivity matrix that shows the sensitivity of the branch phase-angle differences, and therefore the real power flows, to branch capacities.

Modeling the Network

DC Model--

A slightly modified version of the DC load-flow model as given by Kaltenbach et al. (1970) is used. Every load or generation center is represented by a node. The variable associated with each node is the voltage phase angle. The control variable associated with every node is the net real-power injection at the node. Each set of parallel lines between two nodes is represented by a branch. Each branch is characterized by a capacity that is the sum of the capacities of individual lines comprising the branch. The capacity of a branch is:

$$Y_{\{ij\}} \doteq \sum_{\alpha=1}^{S} \frac{V^2_{\{ij\},\alpha} X_{\{ij\},\alpha}}{Z^2_{\{ij\},\alpha}}, \qquad (60)$$

where $V_{ij,\alpha}$ = voltage of line ij , $X_{ij,\alpha}$ = reactance of line ij , $Z_{ij,\alpha}$ = magnitude of the impedance of line ij ,α, and S = number of lines in the branch between nodes i and j. The relationship between lines flows and phase-angle differences is

$$T_{\{ij\},\alpha} = \gamma_{\{ij\},\alpha} \times (\Theta_i - \Theta_j) = \gamma_{\{ij\},\alpha} \times \psi_{\alpha}, \tag{61}$$

where $T_{ij,\alpha}$ = flow in line α between nodes i and j, $\lambda_{ij,\alpha}$ = capacity of this line, Θ_i = phase angle at bus i, Θ_j = phase angle at bus j, and Ψ_α = phase-angle difference between the extremities of line α.

To every line a maximum flow is assigned. For long lines this limit is the stability limit, and for short lines the limit is usually the thermal limit of the line. These flow limits can be translated, using Eq. (61), into phase-angle difference limits. The line with the smallest flow rating sets an upper bound on the phase-angle difference for the branch.

The power-flow model is the DC linear power-flow model Kaltenbach et al. (1970):

$$\sum_{j \in K(i)} \gamma_{\{ij\}} (\Theta_i - \Theta_j) = p_i \qquad i = 1, \ldots, n-1, \tag{62}$$

where K(i) = set of all nodes adjacent to node i, $\gamma_{\{ij\}}$ = capacity of the branch ij , and p_i = net real-power injection at node i. In matrix form, Eq. (62) can be written as

$$D\theta = P, \tag{63}$$

where D = nodal-capacity matrix (to be defined), Θ = vector of bus-phase angles, and P = vector of bus-net-active-power injections.

The matrix D can be called the nodal-capacity matrix. This matrix has the general properties of the bus-admittance matrix, Y_{bus}, with the difference that the elements are capacities rather than admittances. Matrix D can be formed by inspection by using the element bus-incidence matrix:

$$D = A^T (\mathrm{diag}\ \gamma) A, \tag{64}$$

where diag γ = diagonal matrix of branch capacities and A = element bus-incidence matrix.

The vector of phase-angle differences, Ψ, can be formed as follows:

$$\psi = A\Theta \, . \tag{65}$$

Equation (63) forms a set of DC power-flow equations and is solved by LU factorization.

AC Model--

The fast-decoupled AC load-flow model, developed by Stott and Alsac (1974) and described in Section 4, also is implemented. The relationships between real power mismatch and voltage phase angle and between reactive power mismatch and voltage magnitude may be expressed as

$$[\Delta P/V] = [B'] \, [\Delta\theta] \quad \text{and} \tag{66}$$

$$[\Delta Q/V] = [B''] \, [\Delta V] . \tag{67}$$

The solution procedure then follows a prescribed flow (Figure 13). Once a solution is close to convergence, the reactive-power injections at generator bases are calculated and compared with the Q limits of the generator. In cases with Q-limit violations, the bus is converted into a load bus, matrices B' and B" are restructured and factored, and the solution procedure is continued. The bus remains a load bus with its reactive-power injection held at the limiting value unless at some stage it can be converted to a generator bus without the Q-limit violation.

Network Reduction--

Network reduction is needed to let the planner simplify the network and focus on parts that are of interest by representing the external system by simple equivalents. Of the network-reduction methods discussed in Section 5, the classical technique is employed. The REI technique is not used because the identities of buses in the reduced network do not need to be preserved, and the Jacobian-based reduction method is not used because the reduction and planning steps are conducted in two separate programs. These two reduction methods can be used, however; preference should be given to the Jacobian-based reduction since it provides a more accurate representation of the network.

The classical-reduction method is used to represent the external system by physical components. The external system is represented by equivalent injection at the boundary buses, equivalent impedances between boundary buses, and equivalent impedances between boundary buses and ground (Figure 14).

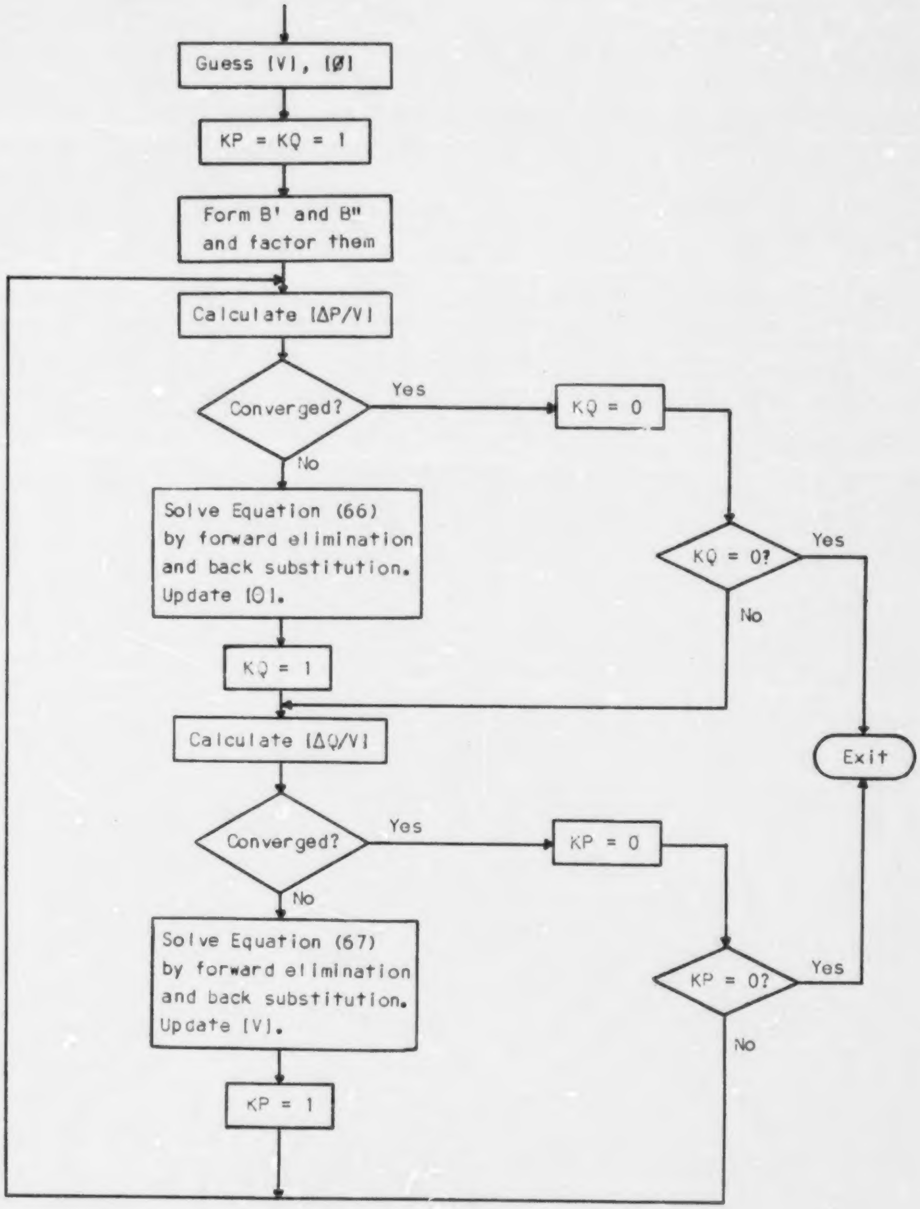
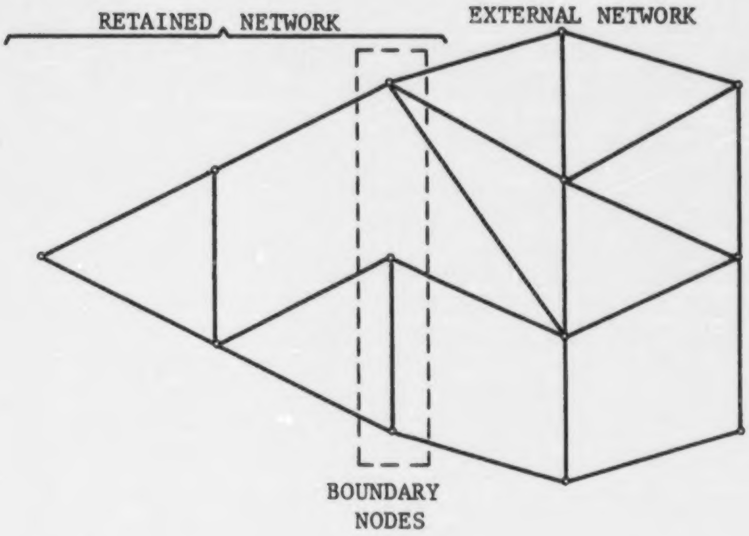
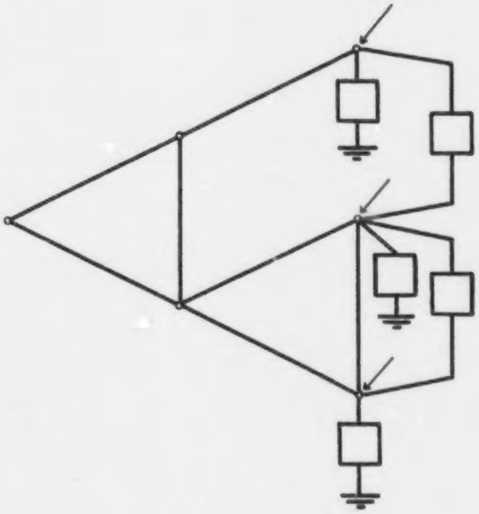

Guess [V], [Ø]
KP = KQ = 1
Form B' and B" and factor them
Calculate [ΔP/V]
Converged?
Yes
No
KQ = 0
Solve Equation (66) by forward elimination and back substitution. Update [Θ].
KQ = 0?
Yes
No
KQ = 1
Calculate [ΔQ/V]
Exit
Converged?
Yes
No
KP = 0
Solve Equation (67) by forward elimination and back substitution. Update [V].
KP = 0?
Yes
No
KP = 1

Figure 13. Flow chart of the fast-decoupled load flow logarithm.


RETAINED NETWORK
EXTERNAL NETWORK
BOUNDARY NODES

(a) Original network.



(b) Reduced network.

Figure 14. Network reduction.

In the DC model the equivalent elements between boundary buses and ground are converted into power injections and are added to the equivalent injections at the boundary buses. Further approximation is made by ignoring the equivalent reactive-power injections. The output of the reduction program for the DC model contains a list of equivalent real-power injections at the boundary buses and a list of the equivalent elements between boundary buses. In the reduction program for the AC model, the only approximation is that the equivalent shunt elements are converted to power injections and are added to the equivalent injections at the boundary buses.

A major difficulty with all reduction techniques is that they produce equivalent elements with values that are not typical of power networks, such as negative resistances and large R/X ratios. These abnormal values may render ill-conditioned the equations to be solved in power-system studies such as paper-flow and planning. In planning, algorithm-high-equivalent costs are assigned to these equivalent elements to bypass them both in decision making processes and in contingency studies. Since the DC model is noniterative, the equivalent elements will cause no convergence problems. Improper selection of buses to be included in the retained network may cause convergence difficulties in the AC model. The bus selection procedure is outlined in Section 8.

The Sensitivity Matrix

In contingency analysis and planning logic, use is made of a sensitivity matrix relating the first-order sensitivities of the branch-phase-angle difference to changes in branch capacities. This matrix was used by Peschon et al. (1967) in their network-planning studies. The relationship between the vector of branch-phase-angle differences and branch capacities is given by

$$\overline{\Delta\psi} = \overline{J}\ \overline{\Delta\gamma} . \tag{68}$$

The sensitivity matrix J is an r x r full matrix, where r is the number of branches, with elements

$$J_{i,j} = \frac{\Delta\psi_i}{\Delta\gamma_j} . \tag{69}$$

The sensitivity matrix can be computed from the formula given in equation Eq. 70 for the DC model (Kaltenbach et al. 1970):

$$\overline{J}(\gamma,\psi) = -A(A^T(\text{diag }\gamma)A]^{-1}\ A^T(\text{diag }\psi) \tag{70}$$

where A = the element bus-incidence matrix (dimension rx(n-1)), diag γ = a diagonal matrix whose elements are the branch capacities (dimension r x r), diag ψ = a diagonal matrix whose elements are the branch phase-angle differences (dimension r x r), r = number of branches, and n = number of nodes. Derivation of this formula is given in Appendix A.

For the AC model the sensitivity matrix can be calculated from Eq. 71:

$$\bar{J}(Y,\psi) = -\hat{A}(B')^{-1}\,\hat{A}^{T}\,\mathrm{diag}\,\psi. \tag{71}$$

where A is the bus-incidence matrix with the column corresponding to the slack bus deleted. Here the matrix J(Y,ψ) has elements $\partial\psi_i/\partial Y_j$ where Y_j is the susceptance of branch j. The matrix B' is that used in the fast-decoupled load-flow equations given in Eq. 72. The derivation of the formula in Eq. 71 parallels that for Eq. 70 with B' substituted for the term in the brackets.

From Eq. 70 the sensitivity matrix for the Pacific Northwest System is shown in Table 1 (Perschon et al. 1967), and the pictorial diagram for this system is shown in Figure B-1. The magnitude of the ij th element indicates the relative effect that changes in capacity of branch j may have on the phase of angle of the ith branch. Based on values shown in Table 1, the critical branches are tabulated in Table 2.

Contingency Analysis

The expanded network must satisfy prescribed reliability criteria. Since every criterion is usually system dependent, and since every company or power pool has its own rules, devising a single criterion that will contain all these criteria in the program is impossible. In planning studies the reliabilty criteria are usually translated into a series of contingency studies and are treated as pass-fail tests. Because of large computer time and storage requirements, transient-stability studies are usually not carried out until near the end of the planning process when the proposed expansion networks have been reduced to a few.

A single-contingency reliability criterion is incorporated in the program. The network is to be designed to withstand any given single-line outage with no cascading overloads for a given load and generation profile. Multiple-contingency tests can be made by removing one line or generator and proceeding as with single-contingency tests.

Contingency studies are usually carried out by a brute force approach, testing all contingencies every time an evaluation of the system performance is needed (Tinney 1977). Recently, a method has been developed for the automatic ranking and selection of contingency cases for a contingency

TABLE 1. THE SENSITIVITY MATRIX FOR THE BASE-CASE PACIFIC NORTHWEST SYSTEM

	1	2	3	4	5	6	7	8	9	10	11	12	13
1	24.5	-1.1	0.78	1.3	1.5	0.73	0.96	9.33	3.5	-0.46	-0.21	-0.15	-0.004
2	15.8	-3.0	-2.3	-3.9	-4.5	-2.1	-2.8	-27.8	-10.6	1.3	0.64	0.47	0.013
3	-3.1	-0.67	-22.9	2.5	14.5	1.39	1.8	-13.4	-11.1	4.6	-20	-0.3	-0.008
4	2.9	0.62	-1.3	9.8	-2.6	5.5	0.72	12.3	-6.2	0.81	0.38	-1.2	-0.034
5	2.06	0.44	-4.8	-1.6	26	-0.91	-1.2	8.8	7.3	2.8	1.3	0.19	0.005
6	-1.3	-0.28	0.62	-4.5	1.2	-13	-17	-5.6	2.8	-0.37	-0.17	-1.3	0.08
7	-1.2	-0.28	0.61	-4.4	1.2	-12	-41	-5.5	2.8	-0.36	-0.17	-1.3	-6
8	-8.7	-1.87	-3.1	-5.2	-6.1	-2.9	-3.8	-37	-14	1.8	0.86	0.63	0.02
9	-5.8	-1.25	-4.5	4.6	-8.7	2.5	3.3	-24	-20	2.6	1.2	-0.55	-0.015
10	-3.7	-0.8	-9.3	2.9	17	1.6	2.1	-15	-13	5.5	2.5	-0.35	-0.01
11	-0.58	-0.12	13	0.46	2.6	0.25	0.33	-2.4	-2.05	0.86	22	-0.05	-0.001
12	1.57	0.34	-0.74	5.3	-1.4	-7.5	-9.8	6.7	-3.4	0.44	0.2	-2.5	0.046
13	0.03	0.005	-0.001	0.08	-0.02	0.24	-23	0.1	-0.05	0.06	0.03	0.03	-6

analysis (Ejebe and Wolkenberg 1978) based on their effect on the voltage-level degradation and circuit overloads. Irisarri et al. (1979) showed, however, that this method may not be reliable and presented a more reliable model using DC load-flows in the performance indices.

TABLE 2. CRITICAL BRANCHES OF THE PACIFIC NORTHWEST SYSTEM

Voltage angle of branch	Influenced most significantly by a change in capacity of the branch
1	1 and 8
2	8 and 1
3	3 and 11
4	8 and 4
5	5 and 8
6	7 and 6
7	7 and 6
8	8 and 9
9	8 and 9
10	5 and 8
11	11 and 3
12	7 and 6
13	7 and 13

The method developed in this report uses the sensitivity matrices defined in the previous subsection. For every branch a number is calculated that shows the relative effect that removal from that branch of λ_{max} units of capacity (or Y_{max} units of susceptance) will have on the system. These effect indices are calculated by

$$E_i = \frac{\gamma_{max}(i)}{r} \sum_{k=1}^{r} J(k,i) \left[\frac{\psi_k}{\psi_{max,k}}\right]^2 \qquad (72)$$

where E_i = the effect index for branch i, $J(k,i)$ = k,ith element of the Jacobian matrix, r = number of branches, $\psi_{max,k}$ = maximum allowable phase-angle difference in branch k, γ_k = phase-angle difference of branch k, and $\gamma_{max}(i)$ = units of capacity to be removed from branch i.

The terms, $\psi_k/\psi_{max,k}$, represent line flows normalized by their flow limits. These normalized flows are raised to a power of 2 to assign a larger penalty to heavily loaded branches. The elements of the sensitivity matrix provide weighting factors. The terms, $\gamma_{max}(i)$, are used to assign greater importance to higher capacity lines.

The effect indices are used to rank branches according to their expected effects on the system. The magnitudes of the effect indices indicate the expected effect that the removal of the largest capacity line from the branch may have on the system. For contingency studies the branch with the largest effect index is outaged first. The results of the load flow are checked for overloads. Then the branch with the next largest effect index is outaged. This process is repeated until no overloads are observed over several successive contingency cases. Different stopping criteria may be used. Tests on the IEEE 14-Bus Test System and the Wisconsin Upper Michigan Systems' reduced network show that with the stopping criterion of "no overloads over four successive outages" the results are identical to those obtained using the brute force contingency approach.

This method reduces significantly the number of contingency-study cases. Test results show that using the AC model for the 26-bus model of the Wisconsin Upper Michigan System, over 4 yr of planning, the number of contingency studies is 45 as opposed to 261 obtained using the brute force method. These results are discussed further in Section 8. The flow chart for this subroutine is shown in Figure 15.

The Cost Vector

In the method reported here we assume that the capital cost of a line is represented by a series of equal annual installments that include depreciation and interest charges. We also assume that these equal installments will span the entire planning period. Operating costs are taken to be the cost of thermal-energy loss over one planning period. Cost per unit capacity addition on a branch is represented by a function

$$f_k = (C_k + n\mathcal{L}_{\gamma_k}) \times \varepsilon_k \tag{73}$$

where f_k = total cost per unit capacity addition in branch k, C_k = capital cost installments per unit capacity addition in branch k (annual fixed charges), n = cost of one unit of power lost over 1 yr, $\mathcal{L}_{\gamma_k}$ = variation of losses with respect to changes in branch capacity (derived in Appendix A), and ε_k = a factor representing the environmental costs per unit capacity addition of branch k.

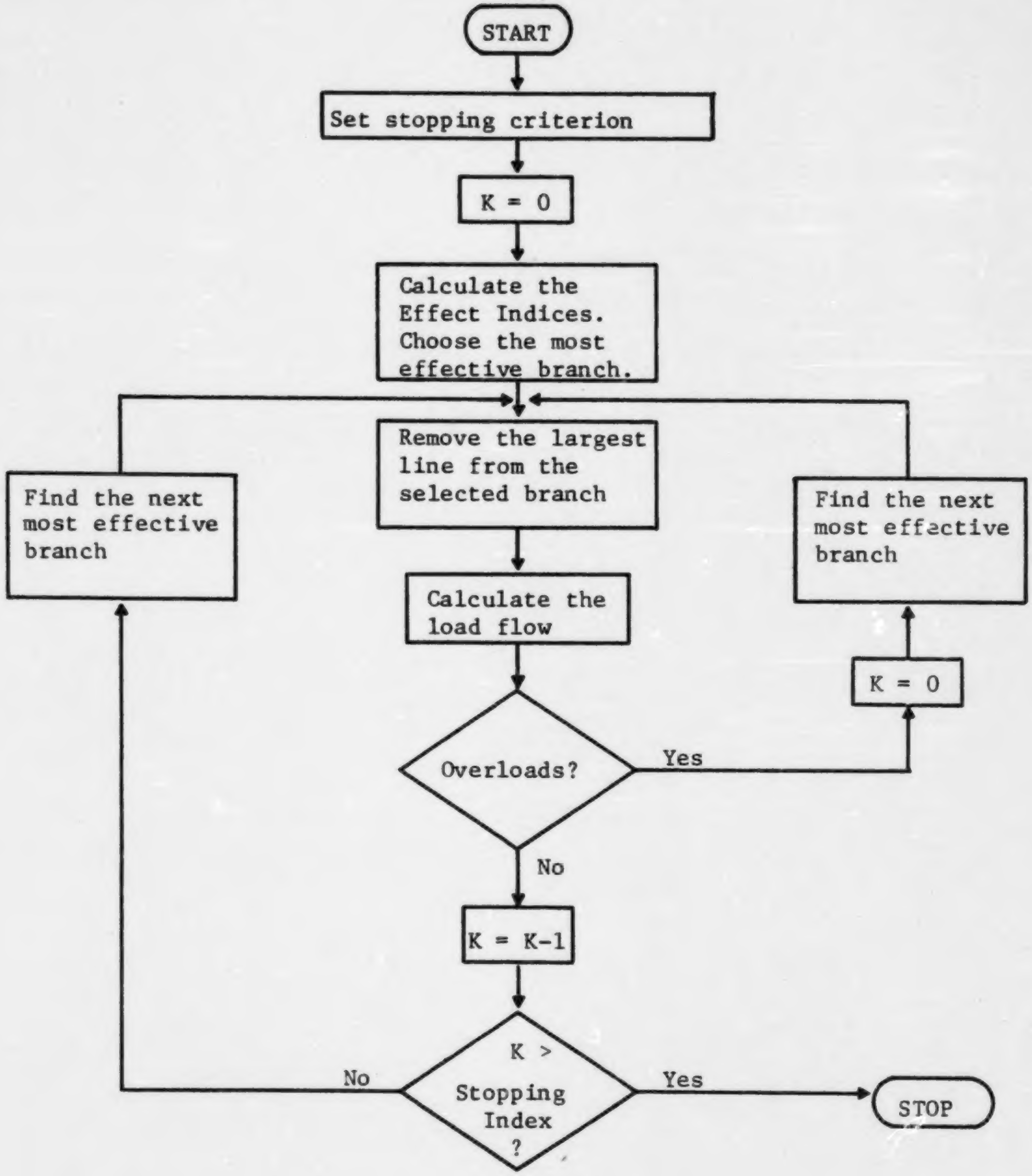

START
Set stopping criterion
K = 0
Calculate the Effect Indices. Choose the most effective branch.
Remove the largest line from the selected branch
Calculate the load flow
Overloads?
Yes
K = 0
Find the next most effective branch
No
K = K-1
K > Stopping Index ?
Yes
STOP
No
Find the next most effective branch

Figure 15. Flow chart of the contingency selection subroutine.

The environmental cost, ε_k, is usually treated as a "go, no go" type factor. This treatment is used because as yet no useable methods exist to assign dollar values to these costs, which may include environmental, political, or other factors. These factors can be manipulated to inhibit addition of lines over a particular right-of-way. For example, if for some reason no line can be added on a particular right-of-way, an arbitrary large environmental cost can be assigned to this right-of-way to prevent its consideration by the automatic-expansion algorithm. Methods are needed that will assign dollar values to the environmental costs and normalize them to show their relative values compared to capital and operational costs of adding lines, in which case this term can be considered as an additive in the cost function.

The Planning Logic

The planning logic is divided into two parts: overload logic and voltage-correction logic. The AC model includes the overload and the voltage-correction logics. The DC model handles the overload logic only.

The Overload Logic--

The overload logic utilizes the sensitivity matrices given by Eq. (70) or Eq. (71), to find the least costly network changes to alleviate line overloads. This is a simple approach and can be classified as a heuristic method that treats the problem as a sequence of unconstrained minimization problems. The approach requires two assumptions: (1) transmission capacity of a branch can be increased by adding lines only, and (2) only specific types of lines or voltage levels that are provided to the program can be used in expanding the system.

In the absence of an input table containing types of lines from which selection is made, the line types already existing on rights-of-way are used during the line selection process.

The minimization logic begins with the assumption that the existing network satisfies the reliability criteria. Then the network-power injections are set to their predicted values for the first year of study and a series of outage tests as prescribed by the reliability criterion are carried out. After each outage test a vector showing branch phase-angle differences is formed. During successive outage tests, the values of elements of this vector are updated if the new values are larger than the previous ones. This procedure results in a vector showing the largest phase-angle differences that occur during the outage tests. This vector is compared to a vector showing the maximum allowable branch phase-angle differences, and overloaded branches are found.

The first step in the overload logic is that for every overloaded branch a vector is formed whose elements are

$$F_i(j) = \frac{J(i,j)}{\text{cost}(j)\left[\dfrac{\Delta\psi_i}{J(i,j)}\right]} \qquad \begin{array}{l} j = 1, \ldots, r \\ i = \{\text{overloaded branches}\} \end{array} \tag{74}$$

where $F_i(j)$ = the merit index of branch j for the overloaded branch i, $J(i,j)$ = the i,j th element of the sensitivity matrix, $\Delta\psi_i$ = deviation from the maximum alowable phase-angle difference in branch i, cost(j) = cost of adding one unit of capacity in branch j (as discussed above). The term in the denominator indicates the relative cost of reinforcing the j th branch to alleviate an overload in the i th branch. The largest of these merit indices points to the most economical branch to be reinforced for an overload in the ith branch. The branches to be reinforced are indicated for all overloaded branches.

The next step is to determine an effect index for all the branches found in the overload logic. This index, which shows the relative effect that the reinforcement of the branch may have on all other overloaded branches, is found from Eq. (75):

$$I_i = \frac{1}{m} \sum_j J(i,j) \qquad j = \{\text{overloaded branches}\} \tag{75}$$

where I_i = effect index of branch i, $J(i,j)$ = the i,jth element of the sensitivity matrix, and m = number of overloaded branches. The largest of these effect indices indicates the branch reinforcement with the greatest effect on all overloaded branches. The logic here is that, of all the reinforcements to be made, performing the most effective one not only eliminates the overload in the desired branch but also has a greater effect in reducing the amount of overloads in all other overloaded branches.

The third step in the overload logic is that the minimum amount of capacity addition to the branch is calculated from Eq. 76:

$$\Delta\gamma_j = \frac{\Delta\psi_i}{J(i,j)} \tag{76}$$

where $\Delta\gamma_j$ = minimum amount of capacity addition to branch j, $\Delta\psi_i$ = deviation from the maximum allowable phase-angle difference in branch i, and $J(i,j)$ = i,j th element of the sensitivity matrix.

The fourth and last step in the overload logic lines or combination of lines that will provide the needed amount of capacity are chosen from the table showing available line types for branches and branches are reinforced accordingly.

These four steps are repeated until all overloads are eliminated. The flow chart for this line-addition subroutine is shown in Figure 16.

The Voltage-Correction Logic--

The voltage-correction logic is included in the AC model only. After the overload-elimination procedure is completed, the voltage-correction logic is initiated to set the bus voltage magnitudes within the limits that are input to the program. Four steps are used in the voltage-correction subroutine (Figure 17). (1) The contingency tests are carried out and the vector is formed that shows the largest voltage-magnitude deviations from the specified limits for every bus during the contingency tests. (2) From Eq. (67), $[\frac{\Delta Q}{V}] = [B''] [\Delta V]$, the vector $[\Delta Q]$ that shows the adjustments to the bus reactive powers that are needed to bring the voltage magnitudes within the specified limits is calculated. (3) These reactive-power adjustments are converted to equivalent susceptances and added to the network. (4) This procedure is repeated until all voltage magnitudes are within the limits. The results show that for a given set of voltage deviations several iterations of this algorithm are needed to bring the voltages within the specified limits.

Future Line Removals

Since it may be more economical to perform some network reinforcements earlier than necessary if they eliminate the need for some other line additions, an algorithm is developed to check the necessity of the network reinforcements for the security of the system after passage of some time. Lines that were added before and are no longer vital for the security of the network are removed. Based on this information, the planner may decide to perform some line additions earlier than indicated by the planning program to realize a net saving in cost.

This algorithm may be considered as the reverse of the contingency-selection logic. Four steps are used in this algorithm (Figure 18). (1) After a specified number of periods new effect indices for the branches that have been reinforced are calculated from:

$$E_i = \frac{1}{r} \sum_{k=1}^{r} J(k,i) \frac{\psi_k}{\psi_{max,k}} . \qquad (77)$$

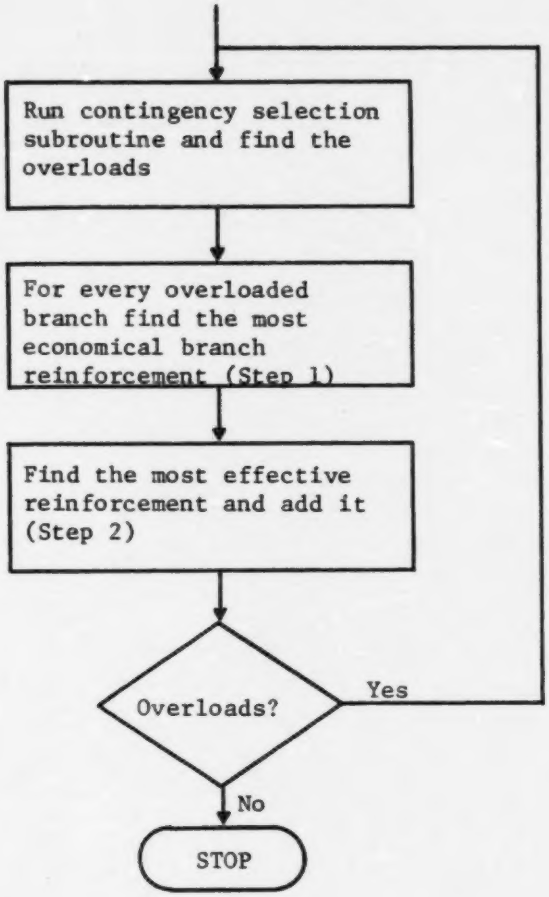

Run contingency selection subroutine and find the overloads
For every overloaded branch find the most economical branch reinforcement (Step 1)
Find the most effective reinforcement and add it (Step 2)
Overloads?
Yes
No
STOP

Figure 16. The line-addition subroutine.

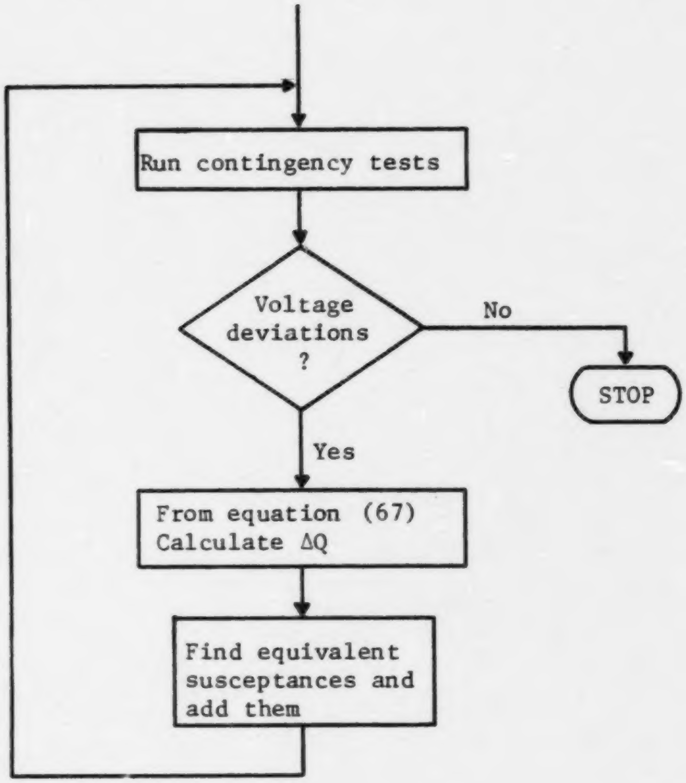

Run contingency tests
Voltage deviations ?
No
STOP
Yes
From equation (67) Calculate ΔQ
Find equivalent susceptances and add them

Figure 17. Flow chart of the voltage-correction subroutine.

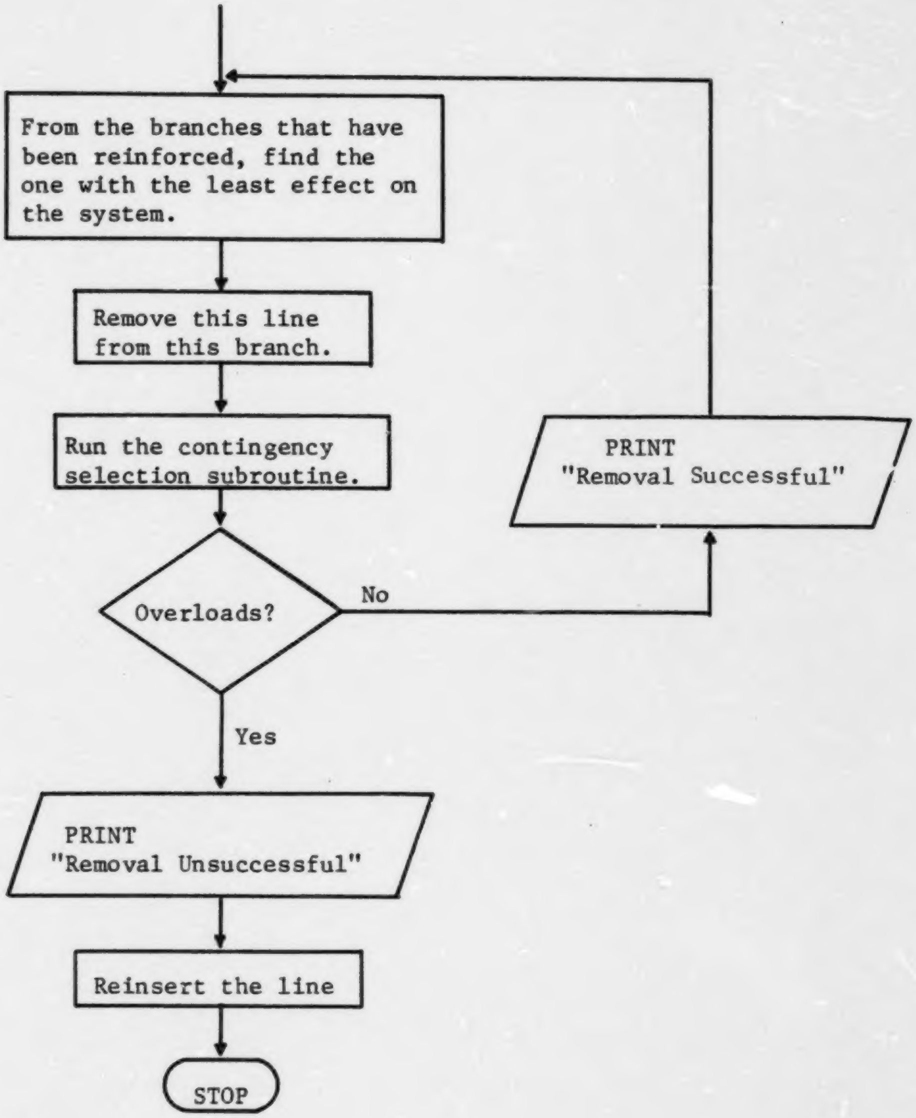

From the branches that have been reinforced, find the one with the least effect on the system.
Remove this line from this branch.
Run the contingency selection subroutine.
Overloads?
No
PRINT "Removal Successful"
Yes
PRINT "Removal Unsuccessful"
Reinsert the line
STOP

Figure 18. Flow chart of the line-removal subroutine.

(2) The smallest of these numbers indicates the branch with least effect on the voltage phase-angle differences of the network. (3) Lines previously added to the network are removed one at a time from the branch thus found. (4) The results of the load flow are checked for overloads. If no overloads are detected, the removal is termed successful and the procedure is repeated.

DISCUSSION

In the AC model, an extension of the DC model, the overload logic is carried out first (Figure 19 and Figure 20). The logic behind this apparent

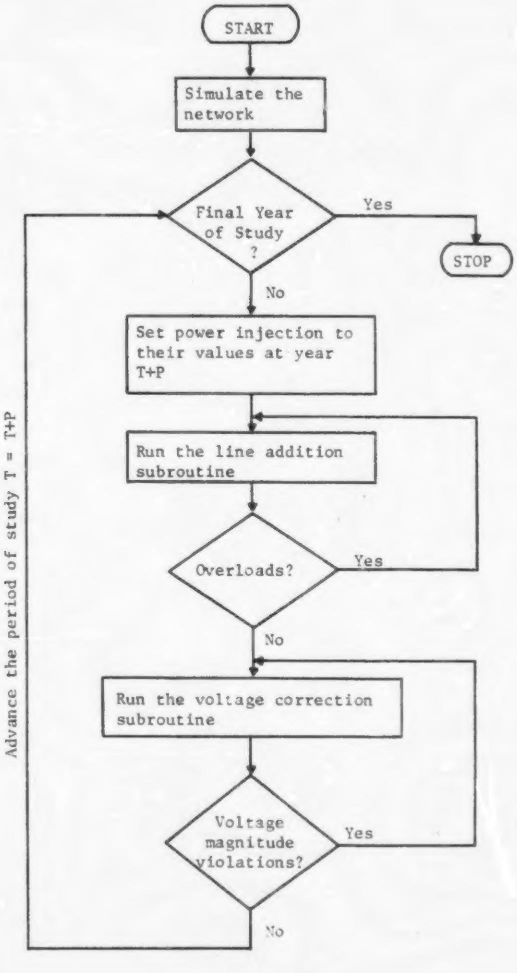

START
Simulate the network
Final Year of Study ?
Yes
STOP
No
Set power injection to their values at year T+P
Run the line addition subroutine
Overloads?
Yes
No
Run the voltage correction subroutine
Voltage magnitude violations?
Yes
No
Advance the period of study T = T+P

Figure 19. Flow chart of the AC model.

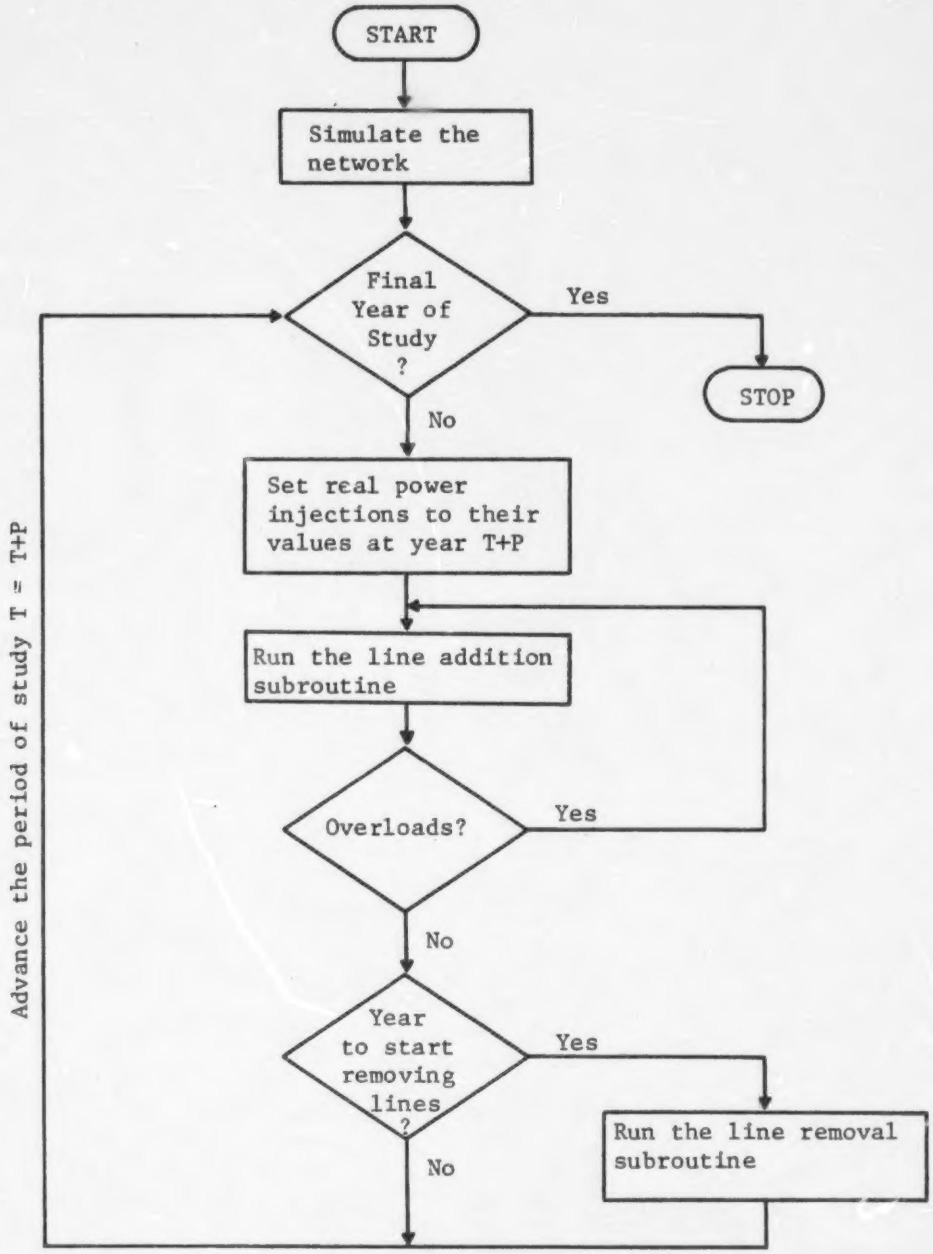

START
Simulate the network
Final Year of Study ?
Yes
STOP
No
Set real power injections to their values at year T+P
Run the line addition subroutine
Overloads?
Yes
No
Year to start removing lines ?
Yes
Run the line removal subroutine
No
Advance the period of study T = T+P

Figure 20. Flow chart of the DC model.

reversal of the planning process is that line additions are considered as major decisions, as opposed to voltage-correction schemes that are viewed as minor decisions and can be considered as after thoughts to major decisions.

In practice, voltage correction is carried out by (1) use of automatic tap changing under load transformers, (2) varying generation VAR outputs, (3) changing fixed taps on transformers (major, semi-permanent changes), (4) adding static VARS to load buses, and (5) adding lines for voltage support (not because flow capacity is required).

In this report several assumptions were made. First, it was assumed that the network is to be expanded for the specified generation profile. Furthermore, to simplify the load-flow model, transformer tap changing under load (TCUL) was not implemented, although clearly the inclusion of TCUL in the power flow is necessary in the final stages of system planning. Static VARS was added to correct the voltage deviations. Uncommonly large VAR additions should signal the planner that other actions should be taken to correct the voltage. The system should also be studied under light load conditions to ensure that the voltages will stay within the specified limits and to determine where partial switching of capacitor banks is necessary. Finally, in the overload logic large numbers of line additions to a given branch should signal the planner that other measures, such as lines of higher voltage, should be used to reinforce the branch.

SECTION 8

EXAMPLES OF PLANNING STUDIES

Sample planning studies were carried out using network data for a simplified model of the Pacific Northwest System (Peschon et al. 1967), the IEEE 14-Bus Test System, and a 26-bus reduced model of a portion of the Wisconsin Upper Michigan System (WUMS) for 1977 (Table 3). Since these data appear in different formats, several editing programs were written to rewrite the data into a format usable by the network-planning program.

TABLE 3. SUMMARY OF SAMPLE PLANNING STUDIES

Study network	Model used	Appendix	Comments
Pacific Northwest 8-bus	DC	B	Eight planning periods. Includes line-removing procedure.
WUMS 26-bus	DC	C	Two planning periods. No line-removal subroutine used.
IEEE 14-bus	AC	D	Four planning periods. Shows bus isolations.
WUMS 26-bus	AC	E	Two planning periods. Shows line additions and voltage correction.

Unfortunately, necessary capital and environmental cost data and projections of forecasted loads and generation for these systems were not available; therefore, arbitrary values were assumed. The purpose of this section is to show the applicability of the technique of network expansion-planning developed in this report. The planning engineer will have access to the necessary data and will be able to use the computer program developed here with his data.

PREPARATION OF DATA

For any network under study the following data are needed:

I. Bus data.
  A. Bus number (buses should be numbered sequentially).
  B. Bus type: PV, PQ, or slack (not needed for the planning program using the DC model).
  C. Bus values: real power, reactive power, voltage magnitude, and voltage phase-angle, depending on the bus type. In the listing of every program the coding for bus type and values is indicated. For the DC model, only theoretical power injections are needed.
  D. Susceptance at the bus (not needed for the DC model).
  E. Bus reactive power limits (not needed for the DC model).

II. Line data.
  A. Terminal bus numbers for the line.
  B. Resistance, reactance, and line charging in per-unit values.
  C. Line-flow limits; for the AC model the flow limits are in MW.
  D. Capital and environmental costs (yearly installments) per unit of capacity addition.

III. Transformer data (same as the line data except that instead of line charging the tap position is given).

IV. Future bus data (future load and generation values for every bus).

SELECTION OF THE BUSES IN THE RETAINED NETWORK

For planning studies it is often desirable to focus on that portion of the network that is of interest to the planner and to represent the external network by simple equivalents. Since the planning program handles networks of limited size, the size of the network may also have to be reduced. Care should be taken in selecting the buses to be included in the retained portion. These buses should be close electrically and the number of boundary buses between the retained and the external system should be reduced. The number of new equivalent lines is found from

$$r = \sum_{i=1}^{n-1} i \qquad (78)$$

where r = number of new branches and n = number of boundary buses. The original slack bus should be included in the retained network to provide a more accurate representation of the entire system.

THE PACIFIC NORTHWEST SYSTEM: DC MODEL

The simplified Pacific Northwest System (Kaltenbach et al. 1970) is shown in Appendix B. The power injections at every bus were increased by 5% over seven planning periods. After the fourth planning period the line-removing subroutine was activated, and for this system, with a monotonically increasing load and generation profile, no lines could be removed. To demonstrate the operation of the line-removing subroutine over the eighth planning period, however, the magnitude of all loads was reduced, and the results showed that one line added earlier may have been unnecessary. Since the cost data for this network were not available, arbitrary cost values were assigned to all branches. The output of the program is shown in Appendix B.

THE WISCONSIN UPPER MICHIGAN SYSTEM (WUMS): DC MODEL

The simplified interconnection diagram for the servicing areas of Madison Gas and Electric and Wisconsin Power and Light Company is shown in Appendix C. The external system was reduced using the data for a 204-bus model of the 1977 WUMS system. The original slack bus (Prairie Island) was included in the retained portion. As with the Pacific Northwest model, since the cost data were unavailable, uniform costs were assigned to all branches. The network was expanded over two planning periods. Loads were increased by 6%, approximately equivalent to a 2 yr growth, while generation at the Columbia Generating Station was increased from 514 MW to 1028 MW. The output is shown in Appendix C. For the load and generator scheduling mentioned above, the program indicates the need for a 345/138-KV transformer at Rockdale and a 138-KV transmission line between Columbia and Portage.

THE IEEE 14-BUS TEST SYSTEM: AC MODEL

For the Institute of Electrical and Electronics Engineers 14-Bus Test System, the data on the ratings of lines were not available. These values were selected rather arbitrarily. Furthermore, uniform cost data were assigned to branches. The AC model was used with these data, and the program output is shown in Appendix D. The one-line diagram for the IEEE 14-Bus Test System is shown in Appendix D. One salient feature of this output is that during the first planning period, bus 8 was isolated and the program recommended adding a line between buses 7 and 8. Since the data on ratings of lines that are used with this system may not show a realistic expansion plan for the network, however, the case does illustrate the application of the planning program.

THE WUMS NETWORK: AC MODEL

As in the DC case, the 1977 WUMS network was reduced to a 26-model of the service areas of Madison Gas and Electric and Wisconsin Power and Light Company with the Prairie Island generating station retained as the slack bus. With the same load and generation scheduling as in the DC model, the output was obtained (Appendix E). This output indicates the same expansion plan for the network as the one obtained with the DC model (see Appendix C). (The AC and DC models probably yield different expansion plans if the studies are carried out over many planning periods.) In addition, for the assumed voltage magnitude limits of 1.1 to 0.96 p.u. volts, a schedule of bus-susceptance additions is given to bring voltages within the desired limits.

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APPENDIX A

DERIVATIONS OF THE SENSITIVITY MODELS

THE SENSITIVITY MATRIX

First-order sensitivity of ψ, the phase angle difference vector, to changes in branch capacities, also called the Jacobian matrix, can be derived as follows (Peschon et al. 1967). Equation 62 can be written as

$$G(\theta,\gamma) = 0 \ . \tag{A-1}$$

Expanding in a Taylor series, we can write Eq. (A-1) as

$$\begin{aligned} G(\theta + \Delta\theta,\ \gamma + \Delta\gamma) = G(\theta,\gamma) &+ G_\theta\ \Delta\theta \\ &+ G_\gamma\ \Delta\gamma + \text{H.O.T.} = 0 \ . \end{aligned} \tag{A-2}$$

A first-order approximation of equation (A-2) leads to

$$G_\theta\ \Delta\theta + G_\gamma\ \Delta\gamma = 0 \ . \tag{A-3}$$

Solving Eq. (A-3) for $\Delta\theta$, we get

$$\Delta\theta = -G_\theta^{-1}\ G_\gamma\ \Delta\gamma \ . \tag{A-4}$$

Premultiplying both sides by the incidence matrix A and recalling Eq. (65), $\psi = A\theta$, we get

$$\Delta\psi = -A\ G_\theta^{-1}\ G_\gamma\ \Delta\gamma \ . \tag{A-5}$$

This leads to

$$\Delta\psi = B\Delta\gamma \text{ ,} \tag{A-6}$$

where the matrix B, the sensitivity matrix, is given as

$$B = -A(A^T (\text{diag } \gamma \ A)^{-1} A^T \text{ diag } \psi \text{ .} \tag{A-7}$$

The sensitivity matrix is an r x r non-sparse matrix where r is the number of branches.

SENSITIVITY OF ACTIVE POWER LOSS TO CHANGES IN BRANCH CAPACITIES

To approximate the variations of the loss of active power when the branch capacities are modified, we proceed as follows. The system losses can be represented (Peschon et al. 1967) by

$$L(\theta,\delta) = \frac{1}{\mu} \sum_{k=1}^{r} \gamma_k \, (\theta_i - \theta_j)^2 \text{ ,} \tag{A-8}$$

where $\mu = x_{ij}/R_{ij}$. The Lagrangian $\mathcal{L}(\theta,\gamma)$ can be formed from equations (A-1) and (A-8) as

$$\mathcal{L}(\theta,\gamma) = L(\theta,\delta) + \lambda^T G(\theta,\gamma) \text{ .} \tag{A-9}$$

Differentiating Eq. (A-9) with respect to θ and setting it equal to zero, we get

$$L_\theta + \lambda^T G_\theta = 0 \text{ .} \tag{A-10}$$

Expressions for G_θ, G_γ, L_θ, and L_γ, are obtained from Eq. (A-8), Eq. (A.1), Eq. (63), and (Eq. 64) as:

$$G_\theta = A^T (\text{diag } \gamma) A \tag{A-11}$$

$$G_\gamma = A^T(\text{diag}\ \psi) \qquad \text{(A-12)}$$

$$L_\theta = \frac{2}{\mu} A^T(\text{diag}\ \gamma))A\theta = \frac{2}{\mu} P \qquad \text{(A-13)}$$

$$L_\gamma = \frac{1}{\mu} [\text{diag}\ \psi]^2 \ . \qquad \text{(A-14)}$$

Substituting from Eq. (A-11) and Eq. (A-13) into Eq. (A-10), we get

$$\lambda = -\frac{2}{\mu}\theta \qquad \text{(A-15)}$$

Peschon et al. (1967) showed that the incremental loss, ΔL, can be written as

$$\Delta L = \mathcal{L}_\gamma \Delta_\gamma + \text{H.O.T.} \qquad \text{(A-16)}$$

Differentiating Eq. (A-9) with respect to γ, we get

$$\mathcal{L}_\gamma = L_\gamma + \lambda^T G_\gamma \qquad \text{(A-17)}$$

Substituting the expressions for L_γ, λ, and G_γ from equations (A-14), (A-15), and (A-12), respectively, into Eq. (A-17) and then into Eq. (A-16), we get

$$\Delta L = [\ \frac{1}{\mu} [\text{diag}\ \psi]^2 - \frac{2}{\mu} \theta^T A^T(\text{diag}\ \psi) \approx \Delta\gamma \ . \qquad \text{(A-18)}$$

Equation (A-18) shows first-order variations of losses with respect to changes in branch capacities.

REFERENCE

Peschon, J., and J. C. Kaltenbach. 1967. Power system planning and reliability. Final report. SRI project 6619, Contract 14-03-72910. Stanford Research Institute, Menlo Park, California.

APPENDIX B

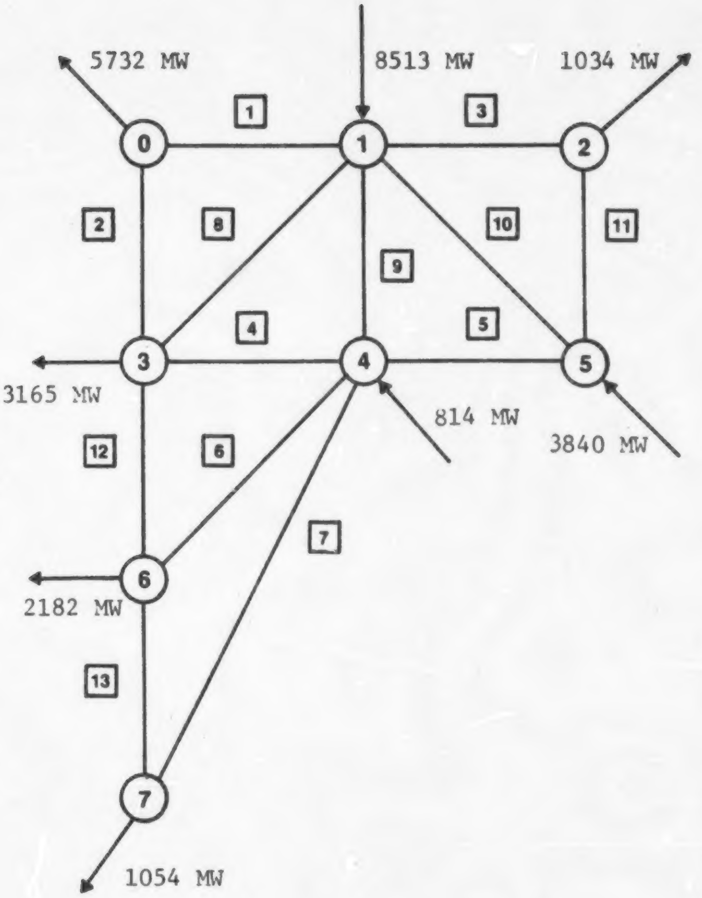
EXAMPLE PLANNING STUDY FOR THE PACIFIC NORTHWEST SYSTEM (DC MODEL)

INTRODUCTION

The 8-bus simplified model of the Pacific Northwest System was studied using data obtained from Peschon et al. (1967). The simplified network diagram is shown in Figure B-1. The base MVA is set equal to 100. For each planning period the power injections are increased by 5%. During the fourth planning period the line-removing subroutine is activated. For a monotonically increasing load and generation profile, no lines can be removed. To show the operation of the line-removing subroutine, at the eighth planning period the power injections are reduced and one line previously added can then be eliminated. For each planning period a table showing the results of outage studies is printed. During every iteration a list of all overloaded branches is presented, followed by the minimum amount of capacity addition needed to alleviate the most critical overload. Finally, the minimum number of lines that can provide the needed capacity is indicated. The line types refer to the order in which the line data appear in the input data for a given branch.

THE LINE DATA

The line data for the 8-bus model of the Pacific Northwest System is shown in Table B-1. The line data are modified and are approximate. Bus 0 is the slack bus. The bus-power injections are shown in Figure B-1. Output data is shown in Figure B-2.



5732 MW
8513 MW
1034 MW
1
3
0
1
2
2
8
10
11
9
4
5
3
4
5
3165 MW
814 MW
3840 MW
12
6
7
6
2182 MW
13
7
1054 MW

Figure B-1. Simplified network diagram of the Pacific Northwest System.

TABLE B-1. LINE DATA FOR THE PACIFIC NORTHWEST SYSTEM

From node	To node	Resistance (p.u. ohms)	Reactance (p.u. ohms)	Rating (MW)
0	1	0.000	0.0411	1217.04272
0	1	0.000	0.0411	1217.04272
0	1	0.000	0.0411	1217.04272
0	1	0.000	0.0411	1217.04272
0	1	0.000	0.1214	411.73718
0	1	0.000	0.1214	411.73718
0	1	0.000	0.1214	411.73718
0	1	0.000	0.2719	183.91049
0	1	0.000	0.2763	180.96609
0	1	0.000	0.2763	180.96609
0	1	0.000	0.2763	180.96609
0	1	0.000	0.2763	180.96609
0	3	0.000	0.0456	1095.33838
0	3	0.000	0.0456	1095.33838
0	3	0.000	0.3070	162.86948
1	2	0.000	0.3684	135.72458
1	2	0.000	0.3684	135.72458
1	2	0.000	0.3684	135.72458
1	2	0.000	0.3684	135.72458
3	4	0.000	0.0274	1825.56396
3	4	0.000	0.0274	1825.56396
3	4	0.000	0.0810	617.60571
3	4	0.000	0.1842	271.44910
3	4	0.000	0.1842	271.44910
3	4	0.000	0.1842	271.44910
4	5	0.000	0.0548	912.78198
4	5	0.000	0.0548	912.78198
4	5	0.000	0.0548	912.78198
4	5	0.000	0.0548	912.78198
4	5	0.000	0.1619	308.80286
4	5	0.000	0.3684	135.72458
4	5	0.000	0.3684	135.72458
4	5	0.000	0.3684	135.72458
4	6	0.000	0.0365	1369.17285
4	6	0.000	0.0365	1369.17285
4	6	0.000	0.0365	1369.17285
4	6	0.000	0.0365	1369.17285
4	6	0.000	0.2456	203.58679
4	6	0.000	0.2456	203.58679
4	7	0.000	0.4229	118.22820

(continued)

TABLE B-1 (continued)

From node	To node	Resistance (p.u. ohms)	Reactance (p.u. ohms)	Rating (MW)
1	3	0.000	0.0639	782.38452
1	3	0.000	0.0639	782.38452
1	3	0.000	0.4298	116.33530
1	4	0.000	0.0456	1095.33838
1	4	0.000	0.0456	1095.33838
1	4	0.000	0.3070	162.86948
1	5	0.000	0.0548	912.78198
1	5	0.000	0.0548	912.78198
1	5	0.000	0.3684	135.72458
2	5	0.000	0.0365	1369.17285
2	5	0.000	0.0365	1369.17285
2	5	0.000	0.2456	203.58679
3	6	0.000	0.0228	2190.67676
3	6	0.000	0.0228	2190.67676
3	6	0.000	0.1535	325.73889
3	6	0.000	0.1535	325.73889
6	7	0.000	0.0183	2738.34570
6	7	0.000	0.0183	2738.34570
6	7	0.000	0.1228	407.17365
6	7	0.000	0.1228	407.17365

```
**************************************************

                 GENERAL INFORMATION

TOTAL NUMBER OF BUSES(NOT INCLUDING SLACK BUS)=  7

TOTAL NUMBER OF BRANCHES= 13

NUMBER OF YEARS OF STUDY=  8

COST OF ONE P.U. OF POWER LOSS=$ .7152E-01

PER UNIT POWER BASE=100 MW


**************************************************************************

YEAR 1

       NET INJECTED REAL POWER  MW
  8513.00000   -1034.00000   -3165.00000     814.00000     3040.00000
 -2102.00000   -1054.00000
                                                              OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                              ******************************************
                                                                     8                      8

                                                                     1
                                                                     9
                                                                     4
                                                                     5
                                                                     6


                  ITERATION 1

                  OVERLOAD IN BRANCH  8 BETWEEN BUSES  1 AND  3
                  MIN .4318E+01 P.U. MW IN BRANCH  8 BETWEEN BUSES
                    1 AND  3

                **ADD 1 LINE OF TYPE  1 IN BRANCH  8
                  CAPACITY =   15.6495 P.U. MW
                                                              OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                              ******************************************
                                                                     1
                                                                     8
                                                                     9
                                                                     4
                                                                     5

ITERATION 2
```

Figure B-2. Output of the planning program, Pacific Northwest system (DC model).

```
                NO OVERLOADS IN YEAR  1   ITERATION  2


-----------------------------------------------------------------


-----------------------------------------------------------------
YEAR 2

      NET INJECTED REAL POWER  MW
  8938.00000   -1085.00000   -3323.00000     854.00000    4032.00000
 -2291.00000   -1106.00000
                                                              OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                              ****************************************
                                                                      1
                                                                      8
                                                                      9
                                                                      4
                                                                      5


                ITERATION 1


                NO OVERLOADS IN YEAR  2   ITERATION  1


-----------------------------------------------------------------


-----------------------------------------------------------------
YEAR 3

      NET INJECTED REAL POWER  MW
  9384.00000   -1139.00000   -3489.00000     897.00000    4233.00000
 -2405.00000   -1162.00000
                                                              OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                              ****************************************
                                                                      1
                                                                                          1
                                                                      8
                                                                      9
                                                                      4
                                                                      5
                                                                      6
```

```
ITERATION 1

OVERLOAD IN BRANCH  1 BETWEEN BUSES  0 AND  1
MIN .8242E+01 P.U. MW IN BRANCH  1 BETWEEN BUSES
  0 AND  1

**ADD 1 LINE OF TYPE  1 IN BRANCH  1
 CAPACITY =   24.3309 P.U. MW
                                                          OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                         ****************************************
                                                                  8
                                                                  1
                                                                  4
                                                                  5
                                                                  6


ITERATION 2


NO OVERLOADS IN YEAR  3   ITERATION  2



------------------------------------------------------------------------

            NEED TO REMOVE   76.8555 P.U. MW CAPACITY FROM  8

            REMOVE ONE LINE OF TYPE  1 CAPACITY OF   15.6495 P.U. MW FROM BRANCH  8  LOOP  1
                                                OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                               ****************************************
                                                        8
                                                                            8
                                                        9
                                                                            8
                                                        1
                                                        4
                                                        5
                                                        6
                                                       13
            REMOVAL NOT SUCCESSFUL*************


------------------------------------------------------------------------
YEAR 4

     NET INJECTED REAL POWER  MW
  9854.00000   -1196.00000   -3663.00000     942.00000    4445.00000
 -2525.00000   -1220.00000
```

```
                                                                     OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                    ****************************************
                                                                             8
                                                                             1
                                                                             9
                                                                             5
                                                                             6


                   ITERATION 1


                   NO OVERLOADS IN YEAR  4   ITERATION  1


----------------------------------------------------------------------

                              NEED TO REMOVE   41.6550 P.U. MW CAPACITY FROM  8

                              REMOVE ONE LINE OF TYPE  1 CAPACITY OF   15.6495 P.U. MW FROM BRANCH  8  LOOP  1
                                                                     OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                    ****************************************
                                                                             8
                                                                                                    8
                                                                             9
                                                                                                    8
                                                                             1
                                                                                                    8
                                                                             4
                                                                                                    8
                                                                             5
                                                                                                    8
                                                                             6
                                                                                                    8
                                                                            13
                                                                            11
                                                                             2
                                                                                                    8
                                                                            10
                                                                            12
                                                                             7
                                                                             3
                              REMOVAL NOT SUCCESSFUL*************


----------------------------------------------------------------------

YEAR 5

     NET INJECTED REAL POWER  MW
  10346.00000   -1255.00000   -3646.00000     989.00000    4667.00000
  -2651.00000   -1281.00000
                                                                     OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                    ****************************************
                                                                              8
                                                                                                    8
                                                                              1
                                                                              9
                                                                              5
                                                                              6
                                                                              4



                   ITERATION 1

                   OVERLOAD IN BRANCH  8 BETWEEN BUSES  1 AND  3
                   MIN .6973E+01 P.U. MW IN BRANCH  8 BETWEEN BUSES
                     1 AND  3

                 **ADD 1 LINE OF TYPE  1 IN BRANCH  8
                   CAPACITY =   15.6495 P.U. MW
                                                                     OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                    *****************************************
                                                                              8
                                                                              1
                                                                              6
                                                                              5
                                                                              9


                   ITERATION 2


                   NO OVERLOADS IN YEAR  5   ITERATION  2


----------------------------------------------------------------------

                              NEED TO REMOVE   30.9339 P.U. MW CAPACITY FROM  8

                              REMOVE ONE LINE OF TYPE  1 CAPACITY OF   15.6495 P.U. MW FROM BRANCH  8  LOOP  1
                                                                     OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                    *****************************************
                                                                              8
                                                                                                    8
                                                                              1
                                                                              9
                                                                              5
                                                                              6
                                                                              4

                              REMOVAL NOT SUCCESSFUL**************
```

```
----------------------------------------------------------------------
YEAR 0

     NET INJECTED REAL POWER  MW
 11340.00000   -1380.00000   -4230.00000    1087.00000    5133.00000
 -2916.00000   -1409.00000
                                                                        OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                      ****************************************
                                                                                8
                                                                                                     8
                                                                                1
                                                                                                     1
                                                                                6
                                                                                5
                                                                                9
                                                                                4
                                                                               13


                  ITERATION 1


                  OVERLOAD IN BRANCH  1 BETWEEN BUSES  0 AND  1
                  OVERLOAD IN BRANCH  8 BETWEEN BUSES  1 AND  3
                  MIN .3519E+01 P.U. MW IN BRANCH  8 BETWEEN BUSES
                    1 AND  3

                **ADD 1 LINE OF TYPE  1 IN BRANCH  8
                  CAPACITY =   15.6495 P.U. MW
                                                                        OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                      ****************************************
                                                                                1
                                                                                                     1
                                                                                6
                                                                                8
                                                                                5
                                                                                4
                                                                                9


                  ITERATION 2


                  OVERLOAD IN BRANCH  1 BETWEEN BUSES  0 AND  1
                  MIN .7980E+01 P.U. MW IN BRANCH  1 BETWEEN BUSES
                    0 AND  1

                **ADD 1 LINE OF TYPE  2 IN BRANCH  1
                  CAPACITY =    8.2372 P.U. MW
                                                                        OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                      ****************************************
                                                                                1
                                                                                6
                                                                                5
                                                                                8
```

```
              ITERATION 3

              NO OVERLOADS IN YEAR  6   ITERATION  3


-----------------------------------------------------------------
                           NEED TO REMOVE    9.7863 P.U. MW CAPACITY FROM  8

                           SYSTEM ALREADY AT OPERATING LIMIT NO LINE REMOVED


-----------------------------------------------------------------
YEAR 7

      NET INJECTED REAL POWER  MW
 12518.00000   -1518.00000   -4653.00000    1195.00000    5646.00000
 -3207.00000   -1549.00000
                                                                    OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                    ****************************************
                                                                            1
                                                                                                1
                                                                            6
                                                                            5
                                                                            8
                                                                            4
                                                                            9


             ITERATION 1

             OVERLOAD IN BRANCH  1 BETWEEN BUSES  0 AND  1
             MIN .1918E+02 P.U. MW IN BRANCH  1 BETWEEN BUSES
               0 AND  1

           **ADD 1 LINE OF TYPE  1 IN BRANCH  1
             CAPACITY =   24.3309 P.U. MW
                                                                    OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                    ****************************************
                                                                            6
                                                                            5
                                                                            8
                                                                            4
                                                                            1
```

```
                   ITERATION 2

                   NO OVERLOADS IN YEAR  7   ITERATION  2


----------------------------------------------------------------------
                              NEED TO REMOVE   38.6259 P.U. MW CAPACITY FROM  8

                              REMOVE ONE LINE OF TYPE  1 CAPACITY OF   15.6495 P.U. MW FROM BRANCH  8  LOOP  1
                                                                     OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                    ****************************************
                                                                              8
                                                                                                    8
                                                                              6
                                                                              5
                                                                              9
                                                                                                    8
                                                                              4
                                                                                                    8
                                                                              1
                                                                             13
                                                                                                    7
                                                                             11
                                                                             10
                                                                             12
                                                                              7
                                                                              2
                              REMOVAL NOT SUCCESSFUL*************


----------------------------------------------------------------------

YEAR 8

     NET INJECTED REAL POWER  MW
  11380.00000   -1380.00000   -4230.00000    1087.00000    5133.00000
  -2916.00000   -1409.00000
                                                                     OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                    ****************************************
                                                                              6
                                                                              5
                                                                              8
                                                                              4
                                                                              1


                   ITERATION 1
```

```
NO OVERLOADS IN YEAR 8   ITERATION 1


-----------------------------------------------------------------------

                        NEED TO REMOVE  120.3417 P.U. MW CAPACITY FROM  8

                        REMOVE ONE LINE OF TYPE  1 CAPACITY OF   15.6495 P.U. MW FROM BRANCH  8  LOOP  1
                                                                OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                               ****************************************
                                                                        8
                                                                        6
                                                                        5
                                                                        9
                                                                        4

                       *****REMOVAL SUCCESSFUL

                        NEED TO REMOVE   82.0893 P.U. MW CAPACITY FROM  8

                        REMOVE ONE LINE OF TYPE  1 CAPACITY OF   15.6495 P.U. MW FROM BRANCH  8  LOOP  2
                                                                OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                               ****************************************
                                                                        8
                                                                                            8
                                                                        9
                                                                                            8
                                                                        5
                                                                                            8
                                                                        6
                                                                        4
                                                                                            8
                                                                        1
                                                                                            8
                                                                       13
                                                                       11
                                                                       10
                                                                       12
                                                                        2
                                                                                            8
                                                                        7
                                                                        3

                        REMOVAL NOT SUCCESSFUL*************
```

APPENDIX C

EXAMPLE PLANNING STUDY FOR THE WISCONSIN UPPER MICHIGAN SYSTEM (DC MODEL)

INTRODUCTION

The data for the 204-bus reduced model of the Wisconsin Upper Michigan System (WUMS) network was obtained from the WUMS Transmission Planning Task Force. This network was then reduced to a 26-bus network, modeling the bulk transmission network of the Madison Gas and Electric Company and Wisconsin Power and Light Company, with the remainder of WUMS represented by an equivalent. The slack bus at Prairie Island is included in this model.

DATA

During the process of network reduction, buses are renumbered. Table C-1 shows the correspondence between the new and the original WUMS bus numbers. This information is obtained from the editing program called "Linker." The one-line diagram for this network is shown in Figure C-1. Table C-2 shows the line data for this network.

OUTPUT OF THE PLANNING PROGRAM (DC MODEL)

The output of the planning program is shown in Figure C-2. The base MVA is set to 100. During the second planning period all loads are increased by 6% and generation at the Columbia Generating Station is increased by 100% to indicate the operation of the second Columbia unit. Since the cost data were not available, uniform costs are assigned to all branches.

In practice, when generation at the Columbia Generating Station is increased by 100%, outputs of other generating facilities in the system are cut back. The planner would have access to this data, and for each planning period the data on output schedules of all generating sites would be provided to the program.

TABLE C-1. WUMS BUS NUMBERS

New bus numbers	WUMS bus numbers	Bus name abbreviation	Bus name
1	9	NED	Nelson Dewey
2	37	PLA	Platteville
3	46	DAT	Darlington
4	80	EEN	Eden
5	105	LAN	Lancaster
6	112	NOM	North Monroe
7	178	ROR	Rock River
8	288	JAN	Janesville
9	298	MCT	McCue Tap
10	315	SJT	South Janesville Tap
11	386	SPG	Spring Green
12	429	ROE5	Rockdale
13	430	ROE10	Rockdale
14	499	KIR	Kirkwood
15	523	POR	Portage
16	538	COL5	Columbia
17	539	COL10	Columbia
18	575	ACA	Academy
19	584	NOR	North Randolph
20	628	SFL5	South Fond du Lac
21	3005	NMA	North Madison
22	3008	NMA	North Madison
23	3038	WMD	West Middleton
24	3048	FCH	Fitchburg
25	3058	KEG	Kegonsa
26	3810	PRD	Prairie Island

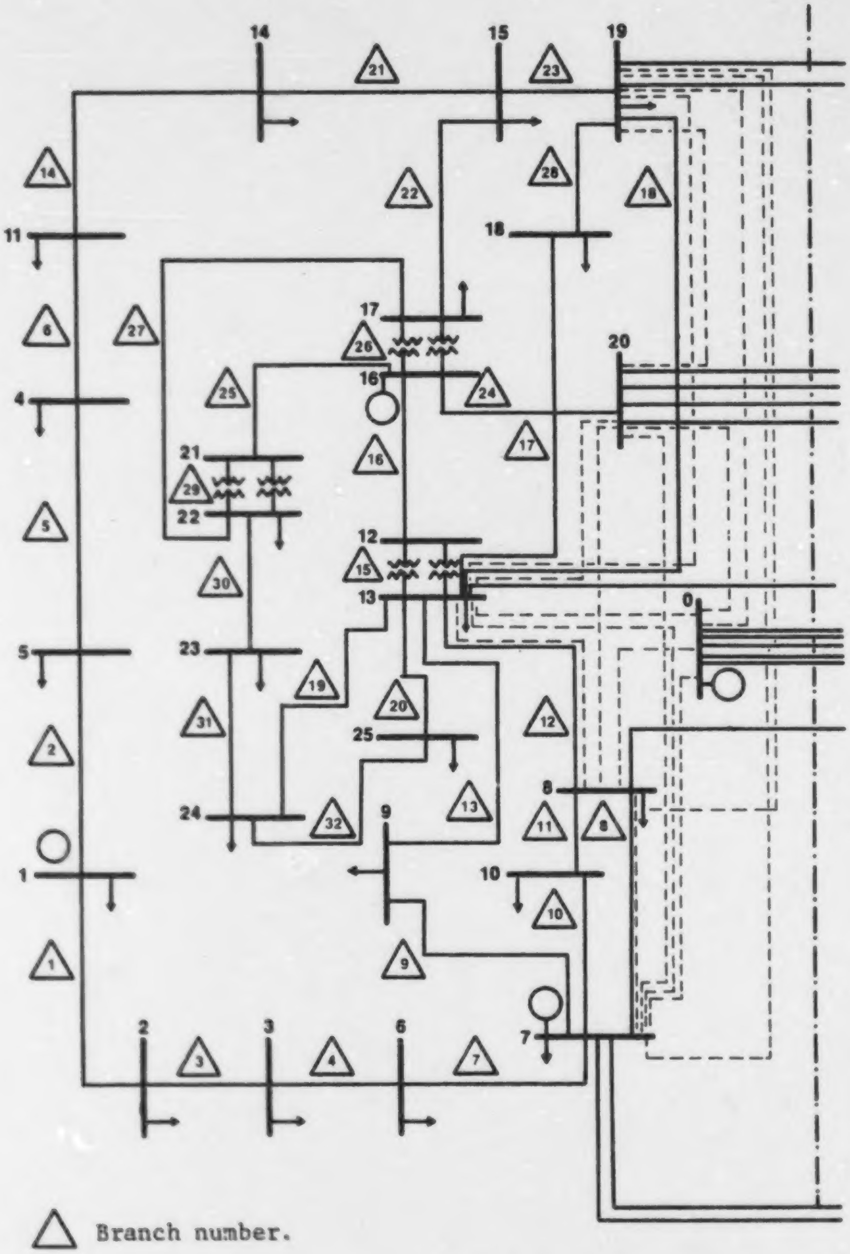

14
21
15
23
19
14
22
28
18
11
18
17
6
27
26
20
25
16
24
4
17
21
29
16
22
5
12
15
30
13
0
5
23
19
20
12
31
2
25
8
24
32
9
13
11
8
10
1
10
9
7
2
3
6
1
3
4
7
Branch number.

Figure C-1. The WUMS reduced DC model.

TABLE C-2. LINE DATA FOR THE WUMS NETWORK, DC MODEL

From node	To node	Resistance (p.u. ohms)	Reactance (p.u. ohms)	Rating (MW)
1	2	0.0195	0.1120	215.0000
1	5	0.0129	0.0739	215.0000
2	3	0.0130	0.0752	215.0000
3	6	0.0517	0.1109	110.0000
4	5	0.0113	0.0653	215.0000
4	11	0.0176	0.1013	215.0000
6	7	0.0696	0.1487	110.0000
7	8	0.0131	0.0401	141.0000
7	8	0.1432	0.4507	0.0000[a]
7	9	0.0157	0.0431	141.0000
7	10	0.0116	0.0232	110.0000
8	10	0.0087	0.0149	110.0000
8	13	0.0304	0.0989	127.0000
8	13	0.5417	1.3879	0.0000[a]
9	13	0.0150	0.0762	141.0000
11	14	0.0185	0.1062	215.0000
13	12	0.0012	0.0515	224.0000
13	12	0.0012	0.0515	224.0000
12	16	0.0022	0.0327	1108.0000
13	18	0.0360	0.1099	141.0000
13	19	0.0533	0.1753	129.0000
13	19	2.1464	4.1909	0.0000[a]
13	24	0.0157	0.0936	143.0000
13	25	0.0065	0.0389	143.0000
14	15	0.0131	0.0750	215.0000
15	17	0.0038	0.0240	215.0000
15	19	0.0150	0.0886	215.0000
16	20	0.0023	0.0348	598.0000
16	21	0.0007	0.0109	1303.0000
16	17	0.0014	0.0573	200.0000
16	17	0.0013	0.0573	200.0000
17	22	0.0103	0.0724	287.0000
18	19	0.0192	0.0585	141.0000

(continued)

TABLE C-2 (continued)

From node	To node	Resistance (p.u. ohms)	Reactance (p.u. ohms)	Rating (MW)
21	22	0.0000	0.0500	224.0000
21	22	0.0000	0.0500	224.0000
22	23	0.0112	0.0738	270.0000
23	24	0.0068	0.0419	270.0000
24	25	0.0110	0.0565	240.0000
20	7	0.0098	0.2234	0.0000[a]
20	8	0.0924	0.3081	0.0000[a]
20	13	0.0402	0.3208	0.0000[a]
20	19	0.0326	0.1281	0.0000[a]
20	0	0.0059	0.1263	0.0000[a]
0	7	0.0239	0.3742	0.0000[a]
0	8	0.3961	1.4434	0.0000[a]
0	13	0.1638	1.7919	0.0000[a]
0	19	0.4097	1.3078	0.0000[a]
19	7	1.4231	3.5847	0.0000[a]
19	8	3.1958	4.3702	0.0000[a]
13	7	0.1854	1.3556	0.0000[a]

[a] Fictitious lines.

```
**************************************************

                 GENERAL INFORMATION

TOTAL NUMBER OF BUSES(NOT INCLUDING SLACK BUS)= 25

TOTAL NUMBER OF BRANCHES= 44

NUMBER OF YEARS OF STUDY= 2

COST OF ONE P.U. OF POWER LOSS=$  .7152-01

PER UNIT POWER BASE=100 MW


------------------------------------------------------------------------

YEAR 1

     NET INJECTED REAL POWER  MW
   157.40000     -18.90000     -14.60000     -19.30000     -7.59990
   -35.59990     -60.27000    -154.28000     -28.40000    -10.60000
   -31.00000        .00000    -137.14000     -36.70000    -33.19990
   514.20000     -27.50000     -21.70000    -167.31000     13.74000
      .00000     -66.79990     -81.19990    -102.59990    -12.79990
                                                                OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                ****************************************
                                                                       16
                                                                       30
                                                                       15
                                                                       23


               ITERATION 1


               NO OVERLOADS IN YEAR 1    ITERATION 1
```

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Figure C-2. Output of the planning program, WUMS system (DC model).

```
----------------------------------------------------------------------

----------------------------------------------------------------------

YEAR 2

        NET INJECTED REAL POWER  MW
   157.90000      -20.03400      -15.47600      -20.45800       -8.05589
   -37.73509      -60.27000     -163.53680      -30.10400      -11.23600
   -32.60000         .00000     -145.36840      -38.90200      -35.19189
  1028.00000      -24.15000      -23.00200     -177.34860       14.57394
      .00000      -92.00789      -66.07189     -108.54389      -13.56789
                                                                        OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                       ****************************************
                                                                              28
                                                                                                 15
                                                                                                 22
                                                                              16
                                                                                                 22
                                                                              30
                                                                               1
                                                                              12
                                                                              15
                                                                                                 15
                                                                              23
                                                                              13
                                                                               4
                                                                              22


            ITERATION 1

            OVERLOAD IN BRANCH 15 BETWEEN BUSES 13 AND 12
            OVERLOAD IN BRANCH 22 BETWEEN BUSES 15 AND 17
            MIN  .1167+02 P.U. MW IN BRANCH 15 BETWEEN BUSES
             13 AND 12

          **ADD 1 LINE OF TYPE  1 IN BRANCH 15
            CAPACITY =   19.4069 P.U. MW
                                                                        OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                                       ****************************************
                                                                              16
                                                                                                 22
                                                                              24
                                                                                                 22
                                                                              30
                                                                               1
                                                                              12
                                                                              23
  ITERATION 2

  OVERLOAD IN BRANCH 22 BETWEEN BUSES 15 AND 17
  MIN  .7377+01 P.U. MW IN BRANCH 23 BETWEEN BUSES
   15 AND 19

**ADD 1 LINE OF TYPE  1 IN BRANCH 23
  CAPACITY =   10.9722 P.U. MW

                                                   OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                  ****************************************
                                                          16
                                                                               22
                                                          24
                                                                               22
                                                          30
                                                                               22
                                                          12
                                                           1
                                                          13
                                                          22


  ITERATION 3

  OVERLOAD IN BRANCH 22 BETWEEN BUSES 15 AND 17
  MIN  .1694+02 P.U. MW IN BRANCH 22 BETWEEN BUSES
   15 AND 17

**ADD 1 LINE OF TYPE  1 IN BRANCH 22
  CAPACITY =   40.6477 P.U. MW

                                                   OUTAGE IN BRANCH    OVERLOAD IN BRANCH
                                                  ****************************************
                                                          16
                                                          24
                                                          12
                                                           1


  ITERATION 4


  NO OVERLOADS IN YEAR  2   ITERATION  4

*************************************************************************
```

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APPENDIX D

EXAMPLE PLANNING STUDY FOR THE IEEE 14-BUS TEST SYSTEM (AC MODEL)

The one-line diagram for the IEEE 14-bus Test System is shown in Figure D-1, bus data for the IEEE 14-Bus Test System is shown in Table D-1, and the line data is shown in Table D-2.

OUTPUT OF THE PLANNING PROGRAM (AC MODEL)

The output of the planning program is shown in Figure D-2. The power base is 100 MVA. Since the cost data were not available, arbitrary uniform values were selected. Furthermore, since data on line and transformer ratings were not available, arbitrary values were assigned. Over four planning periods, bus data are increased by 5%. The output includes intermediate load-flow results during outage tests.

As before, the line type refers to the order in which the line data appear in the input data for a given branch.

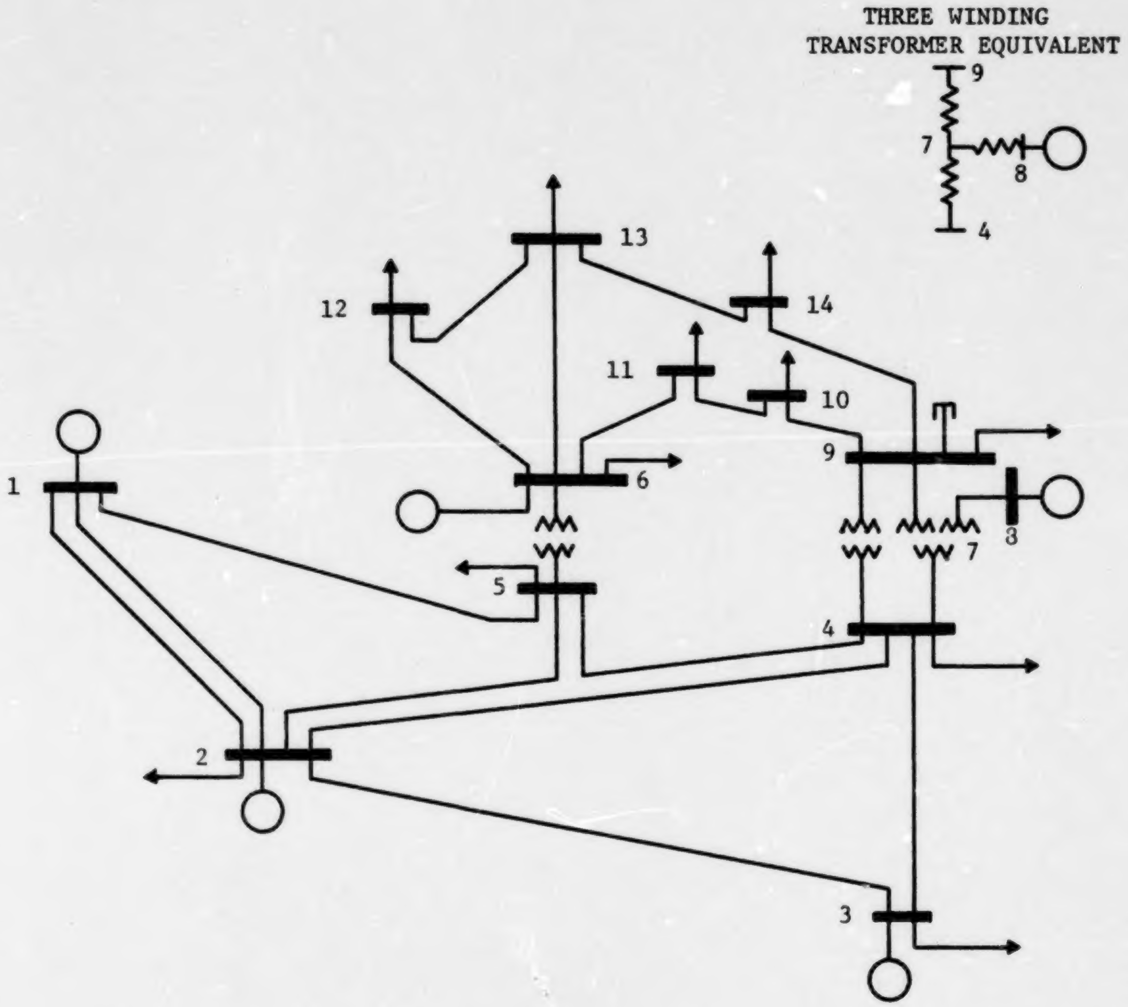
THREE WINDING
TRANSFORMER EQUIVALENT
9
7
8
4
13
12
14
11
10
1
9
6
8
7
5
4
2
3

Figure D-1. One-line diagram of the IEEE 14-Bus Test System.

TABLE D-1. IEEE 14-BUS TEST SYSTEM, MODIFIED BUS DATA

Bus number	Bus type	Voltage magnitude per unit	Voltage phase angle	Generation (p.u. MW)	Load	
					p.u. MW	p.u. MVAR
1	Swing	1.06	0			
2	Generation	1.045		0.183		
3	Generation	1.01		0.942		
4	Load				0.478	-0.039
5	Load				0.076	0.016
6	Generation	1.07		0.112		
7	Load				0	0
8	Generation	1.09		0		
9	Load				0.295	0.166
10	Load				0.09	0.058
11	Load				0.035	0.018
12	Load				0.061	0.016
13	Load				0.135	0.058
14	Load				0.149	0.05

MVA Base = 100.

TABLE D-2. IEEE 14-BUS TEST SYSTEM LINE AND TRANSFORMER DATA

Bus-bus	Type	Resistance per unit	Reactance per unit	Line charging[a] p.u. or transformer tap
1-2	Line	0.01938	0.05917	0.0264
1-5	Line	0.05403	0.22304	0.0246
2-3	Line	0.04699	0.19797	0.0219
2-4	Line	0.05811	0.17632	0.0187
2-5	Line	0.05695	0.17388	0.0170
3-4	Line	0.06701	0.17103	0.0173
7-5	Line	0.01335	0.04211	0.0064
9-4	Transformer	0	0.20912	0.978
6-4	Transformer	0	0.55618	0.969
6-5	Transformer	0	0.25202	0.932
6-11	Line	0.09498	0.19890	0
6-12	Line	0.12291	0.25581	0
6-13	Line	0.06615	0.13027	0
7-8	Transformer	0	0.17615	0
7-9	Transformer	0	0.11001	0
9-10	Line	0.03181	0.08450	0
9-14	Line	0.12711	0.27038	0
10-11	Line	0.08205	0.19207	0
12-13	Line	0.22092	0.19988	0
13-14	Line	0.17093	0.34802	0

[a] Impedance and line charging susceptance in per unit on a 100,000-kva base. Line charging one-half of total charging of line.

```
GENERAL DATA

LIMIT  IDEB   NODE    YEARS        ETA    MVA-BASE      NSUB      V-MAX        V-MIN    IOUTER
  20     1     14       4      2.00000   100.00000        5     1.07100       .98700        4


                                  *BUS DATA
BUS TY         V1           V2            B       Q-MAX        Q-MIN
  1  3      1.06000       .00000       .00000   100.00000  -100.00000
  2  4       .18300      1.04500       .00000   100.00000  -100.00000
  3  4       .94200      1.01000       .00000   100.00000  -100.00000
  4  0       .47800      -.03900       .00000   100.00000  -100.00000
  5  0       .07600       .01600       .00000   100.00000  -100.00000
  6  4       .11200      1.07000       .00000   100.00000  -100.00000
  7  0       .00000       .00000       .00000   100.00000  -100.00000
  8  4       .00000      1.09000       .00000   100.00000  -100.00000
  9  0       .29500       .16600       .00000   100.00000  -100.00000
 10  0       .09000       .05800       .00000   100.00000  -100.00000
 11  0       .03500       .01800       .00000   100.00000  -100.00000
 12  0       .06100       .01600       .00000   100.00000  -100.00000
 13  0       .13500       .05800       .00000   100.00000  -100.00000
 14  0       .14900       .05000       .00000   100.00000  -100.00000
  0  0       .00000       .00000       .00000   100.00000  -100.00000


                                  *LINE DATA
 NS  NR K          R            X            YS       POMAX         ENCO          CAPCO      BRANCH
  1   2 1      .01938       .05917       .02640   285.00000    200.00000      10.00000          1
  1   5 1      .05403       .22304       .02460   100.00000    200.00000      10.00000          2
  2   3 1      .04699       .19797       .02190   112.00000    200.00000      10.00000          3
  2   4 1      .05811       .17632       .01870    91.00000    200.00000      10.00000          4
  2   5 1      .05695       .17388       .01700    93.00000    200.00000      10.00000          5
  3   4 1      .06701       .17103       .01730    76.00000    200.00000      10.00000          6
  4   5 1      .01335       .04211       .00640   387.00000    200.00000      10.00000          7
  7   4 2      .00000       .20912       .97800   200.00000    200.00000      10.00000          8
  9   4 2      .00000       .55618       .96900   200.00000    200.00000      10.00000          9
  6   5 2      .00000       .25202       .93200   200.00000    200.00000      10.00000         10
  6  11 1      .09498       .19890       .00000    58.00000    200.00000      10.00000         11
  6  12 1      .12291       .25581       .00000    45.00000    200.00000      10.00000         12
  6  13 1      .06615       .13027       .00000    84.00000    200.00000      10.00000         13
  7   8 1      .00000       .17615       .00000   162.00000    200.00000      10.00000         14
  7   9 1      .00000       .11001       .00000   246.00000    200.00000      10.00000         15
  9  10 1      .03181       .08450       .00000   167.00000    200.00000      10.00000         16
  9  14 1      .12711       .27038       .00000    41.00000    200.00000      10.00000         17
 10  11 1      .08205       .19207       .00000    65.00000    200.00000      10.00000         18
 12  13 1      .22092       .19988       .00000    27.00000    200.00000      10.00000         19
 13  14 1      .17093       .34802       .00000    31.00000    200.00000      10.00000         20
```

Figure D-2. Output of the planning program, IEEE 14-Bus Test System (AC model).

```
BASE CASE LOAD FLOW RESULTS

BUS    VOLTAGE MAG.    PHASE-DEGREES
-------------------------------------
  1       1.06000          .00000
  2       1.04500          .39553
  3       1.01000         4.61233
  4       1.01579        -1.65465
  5       1.02113        -1.61889
  6       1.07000        -4.69725
  7       1.05053        -4.44341
  8       1.09000        -4.44341
  9       1.03311        -5.90206
 10       1.03196        -6.00582
 11       1.04705        -5.57169
 12       1.05356        -5.78865
 13       1.04691        -5.66954
 14       1.02085        -6.91243
-------------------------------------
-------------------------------------------------- -------------------------------------------------

YEAR 1

    THE BUS DATA FOR THIS YEAR ARE

     BUS  I   TYPE    I     VALUES IN P.U.   I     VALUES IN P.U. OR DEG.  I
    ------I-----------I----------------------I-----------------------------I
       1  I   SLACK   I  V-MAG=      1.06000 I  PHASE=      .00000         I
       2  I    P,V    I   P-IN=       .18300 I  V-MAG=     1.04500         I
       3  I    P,V    I   P-IN=       .94200 I  V-MAG=     1.01000         I
       4  I    P,Q    I  P-OUT=       .47800 I  Q-OUT=     -.03900         I
       5  I    P,Q    I  P-OUT=       .07600 I  Q-OUT=      .01600         I
       6  I    P,V    I   P-IN=       .11200 I  V-MAG=     1.07000         I
       7  I    P,Q    I  P-OUT=       .00000 I  Q-OUT=      .00000         I
       8  I    P,V    I   P-IN=       .00000 I  V-MAG=     1.09000         I
       9  I    P,Q    I  P-OUT=       .29500 I  Q-OUT=      .16600         I
      10  I    P,Q    I  P-OUT=       .09000 I  Q-OUT=      .05800         I
      11  I    P,Q    I  P-OUT=       .03500 I  Q-OUT=      .01800         I
      12  I    P,Q    I  P-OUT=       .06100 I  Q-OUT=      .01600         I
      13  I    P,Q    I  P-OUT=       .13500 I  Q-OUT=      .05800         I
      14  I    P,Q    I  P-OUT=       .14900 I  Q-OUT=      .05000         I
    ------I-----------I----------------------I-----------------------------I


    ********************************************************
    * OUTAGE IN BRANCH      * OVERLOAD IN BRANCH           *
    ********************************************************
    *         6             *                              *
    *         3             *                              *
    *                       *             6                *
    *                       *                              *    *******************************************
    *                       *                              *    *      INTERMEDIATE LOAD FLOW RESULTS     *
    *                       *                              *    *         FOR OUTAGE IN BRANCH   3        *
    *                       *                              *    * BUS     VOLT. P.U.      ANGLE DEG.      *
```

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```
*              *              *     **************************************
*              *              *     *  1         1.06000          .00000  *
*              *              *     *  2         1.04500          .19875  *
*              *              *     *  3         1.01009        10.16149  *
*              *              *     *  4         1.01253         -.24127  *
*              *              *     *  5         1.01920         -.64701  *
*              *              *     *  6         1.07009        -3.80054  *
*              *              *     *  7         1.04926        -3.06670  *
*              *              *     *  8         1.09000        -3.08670  *
*              *              *     *  9         1.03215        -4.58771  *
*              *              *     * 10         1.03119        -4.72992  *
*              *              *     * 11         1.04670        -4.76401  *
*              *              *     * 12         1.05344        -4.67770  *
*              *              *     * 13         1.04680        -4.74237  *
*              *              *     * 14         1.02026        -5.08115  *
*      4       *              *
*      5       *              *
*      2       *              *
*     10       *              *
*              *        1     *
*              *       19     *
*              *              *     **************************************
*              *              *     *     INTERMEDIATE LOAD FLOW RESULTS  *
*              *              *     *        FOR OUTAGE IN BRANCH  10     *
*              *              *     * BUS     VOLT. P.U.      ANGLE DEG.  *
*              *              *     **************************************
*              *              *     *  1         1.06000          .00000  *
*              *              *     *  2         1.04500          .26446  *
*              *              *     *  3         1.01000         4.47610  *
*              *              *     *  4         1.00225        -2.10302  *
*              *              *     *  5         1.01233        -1.41875  *
*              *              *     *  6         1.07009       -11.31063  *
*              *              *     *  7         1.05044        -6.84500  *
*              *              *     *  8         1.09000        -6.88500  *
*              *              *     *  9         1.03862        -9.37933  *
*              *              *     * 10         1.03723       -10.76044  *
*              *              *     * 11         1.05024       -11.93622  *
*              *              *     * 12         1.05301       -13.96338  *
*              *              *     * 13         1.04829       -13.59519  *
*              *              *     * 14         1.02440       -12.24208  *
*      8       *              *
*      9       *              *
*      1       *              *
*     15       *              *


        ITERATION 1

             SYSTEM CONDITION                 I                    CORRECTIVE MEASURE                         I
----------------------------------------------I---------------------------------------------------------------I
OVER LOAD IN BRANCH  1 BETWEEN BUSES  1 AND  2 I                                                               I
OVER LOAD IN BRANCH  6 BETWEEN BUSES  3 AND  4 I                                                               I
OVER LOAD IN BRANCH 19 BETWEEN BUSES 12 AND 13 I                                                               I
```

```
I MIN  .4272+01 P.U. SUSCEPTANCE IN BRANCH  6 BETWEEN BUSES  3 AND  4    I
I ADD  2 LINES OF TYPE 1 IN BRANCH  6 WHOSE R AND X ARE   .06701   .17103I
```

```
***********************************************
* OUTAGE IN BRANCH     * OVERLOAD IN BRANCH    *
***********************************************
*          6           *                       *
*          3           *                       *
*         10           *                       *
*                      *          19           *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*                      *                       *
*          8           *                       *
*          9           *                       *
*          5           *                       *
*          4           *                       *
```

```
*********************************************
*      INTERMEDIATE LOAD FLOW RESULTS       *
*         FOR OUTAGE IN BRANCH  10          *
* BUS      VOLT. P.U.        ANGLE DEG.     *
*********************************************
*  1        1.06000            .00000       *
*  2        1.04500          -.01346        *
*  3        1.01000           1.48988       *
*  4        1.00870          -1.46321       *
*  5        1.01269          -1.02594       *
*  6        1.07000         -12.06046       *
*  7        1.05066          -6.24180       *
*  8        1.09000          -6.24180       *
*  9        1.03906          -8.73502       *
* 10        1.03739          -9.71499       *
* 11        1.05032         -11.28839       *
* 12        1.05302         -11.21341       *
* 13        1.04832         -12.94576       *
* 14        1.02452         -11.59516       *
```

```
ITERATION 2

          SYSTEM CONDITION                    I                     CORRECTIVE MEASURE                                   I
----------------------------------------------I------------------------------------------------------------------------I
OVER LOAD IN BRANCH 19 BETWEEN BUSES 12 AND 13 I                                                                        I
                                              I MIN  .9830+00 P.U. SUSCEPTANCE IN BRANCH 12 BETWEEN BUSES  6 AND 12     I
                                              I ADD 1 LINE OF TYPE  1 IN BRANCH 12 WHOSE R AND X ARE   .12291   .25581
```

```
***********************************************
* OUTAGE IN BRANCH     * OVERLOAD IN BRANCH    *
***********************************************
*          6           *                       *
*          3           *                       *
*         10           *                       *
*          8           *                       *
```

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```
ITERATION 3

            SYSTEM CONDITION                     I                          CORRECTIVE MEASURE                                I
-------------------------------------------------I--------------------------------------------------------------------------I
NO OVERLOADS IN YEAR  1 ITERATION  3             I                                                                          I
BUS  8 IS ISOLATED                               I                                                                          I
                                                 I ADD 1 LINE OF TYPE  1 IN BRANCH 14 WHOSE R AND X ARE   .00000   .17615 I
OVER VOLTAGE AT BUS  7 MAGNITUDE 1.07445         I                                                                          I
UNDER VOLTAGE AT BUS  9 MAGNITUDE  .98698        I                                                                          I
                                                 I ADD     -.05179 P.U.SUSCEPTANCE AT BUS  7                                I
                                                 I ADD      .00027 P.U.SUSCEPTANCE AT BUS  9                                I
UNDER VOLTAGE AT BUS  9 MAGNITUDE  .98688        I                                                                          I
                                                 I ADD      .00190 P.U.SUSCEPTANCE AT BUS  9                                I
NO OVER OR UNDER VOLTAGES                        I                                                                          I

                                 *BUS DATA
BUS TY        V1          V2           B         Q-MAX        Q-MIN
  1  3     1.06000      .00000      .00000   200.00000  -200.00000
  2  2      .19215     1.04500      .00000   200.00000  -200.00000
  3  2      .94910     1.01000      .00000   200.00000  -200.00000
  4  0      .50190     -.04095      .00000   200.00000  -200.00000
  5  0      .07930      .01600      .00000   200.00000  -200.00000
  6  2      .11760     1.07000      .00000   200.00000  -200.00000
  7  0      .00000      .00000      .00000   200.00000  -200.00000
  8  2      .00000     1.09000      .00000   200.00000  -200.00000
  9  0      .30975      .17430      .00000   200.00000  -200.00000
 10  0      .09450      .05800      .00000   200.00000  -200.00000
 11  0      .03675      .01890      .00000   200.00000  -200.00000
 12  0      .06405      .01680      .00000   200.00000  -200.00000
 13  0      .14175      .06090      .00000   200.00000  -200.00000
 14  0      .15645      .05250      .00000   200.00000  -200.00000
  0  0      .00000      .00000      .00000   200.00000  -200.00000
---------------------------------------------------------------- ----------------------------------------

YEAR 2

THE BUS DATA FOR THIS YEAR ARE

 BUS  I   TYPE   I     VALUES IN P.U.     I    VALUES IN P.U. OR DEG.   I
------I----------I------------------------I-----------------------------I
   1  I  SLACK   I  V-MAG=       1.06000  I  PHASE=        .00000       I
   2  I   P,V    I  P-IN=         .19215  I  V-MAG=       1.04500       I
   3  I   P,V    I  P-IN=         .94910  I  V-MAG=       1.01000       I
   4  I   P,Q    I  P-OUT=        .50190  I  Q-OUT=       -.04095       I
   5  I   P,Q    I  P-OUT=        .07980  I  Q-OUT=        .01600       I
   6  I   P,V    I  P-IN=         .11760  I  V-MAG=       1.07000       I
   7  I   P,Q    I  P-OUT=        .00000  I  Q-OUT=        .00000       I
   8  I   P,V    I  P-IN=         .00000  I  V-MAG=       1.09000       I
```

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```
  9  I    P,Q    I  P-OUT=       .10975 I  Q-OUT=       .17430       I
 10  I    P,Q    I  P-OUT=       .09450 I  Q-OUT=       .06090       I
 11  I    P,Q    I  P-OUT=       .03675 I  Q-OUT=       .01890       I
 12  I    P,Q    I  P-OUT=       .06405 I  Q-OUT=       .01680       I
 13  I    P,Q    I  P-OUT=       .14175 I  Q-OUT=       .06090       I
 14  I    P,Q    I  P-OUT=       .15645 I  Q-OUT=       .05250       I
------I----------I----------------------I---------------------------I
```

```
*******************************************
* OUTAGE IN BRANCH     * OVERLOAD IN BRANCH  *
*******************************************
*         6           *          7          *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*                     *                     *
*         3           *                     *
*        10           *                     *
*         8           *                     *
*         9           *                     *
```

```
*****************************************
*     INTERMEDIATE LOAD FLOW RESULTS    *
*        FOR OUTAGE IN BRANCH   6       *
* BUS      VOLT. P.U.       ANGLE DEG.  *
*****************************************
*  1        1.06000          .00000     *
*  2        1.04500          .23613     *
*  3        1.01000         2.98916     *
*  4        1.01537        -1.30194     *
*  5        1.02078        -1.39822     *
*  6        1.07000        -4.75052     *
*  7        1.05878        -4.23007     *
*  8        1.09000        -4.23007     *
*  9        1.03773        -5.77069     *
* 10        1.03541        -5.86782     *
* 11        1.04866        -5.44876     *
* 12        1.05946        -5.35326     *
* 13        1.04817        -5.64789     *
* 14        1.02312        -6.78809     *
```

```
       ITERATION 1

                                                  I                        CORRECTIVE MEASURE                                  I
          SYSTEM CONDITION                        I----------------------------------------------------------------------------I
--------------------------------------------------I                                                                            I
OVER LOAD IN BRANCH  7 BETWEEN BUSES   4 AND   5  I                                                                            I
                                                  I MIN  .2590+01 P.U. SUSCEPTANCE IN BRANCH 10 BETWEEN BUSES  6 AND  5        I
                                                  I ADD 1 LINE OF TYPE  1 IN BRANCH 10 WHOSE R AND X ARE   .00000   .23486
```

```
*******************************************
* OUTAGE IN BRANCH     * OVERLOAD IN BRANCH  *
*******************************************
*         6           *                     *
```

```
   .        3        .              .
   .        8        .              .
   .        5        .              .




        ITERATION 2


             SYSTEM CONDITION                        I
-----------------------------------------------------I-----------------------------------------CORRECTIVE MEASURE-----------------------------I
 NO OVERLOADS IN YEAR  2 ITERATION  2                I                                                                                        I
 OVER VOLTAGE AT BUS  7 MAGNITUDE 1.07170            I                                                                                        I
 UNDER VOLTAGE AT BUS  9 MAGNITUDE  .98039           I                                                                                        I
 UNDER VOLTAGE AT BUS 14 MAGNITUDE  .98579           I                                                                                        I
                                                     I ADD      -.01063 P.U.SUSCEPTANCE AT BUS  7                                             I
                                                     I ADD       .09868 P.U.SUSCEPTANCE AT BUS  9                                             I
 OVER VOLTAGE AT BUS  7 MAGNITUDE 1.07124            I ADD      -.01376 P.U.SUSCEPTANCE AT BUS 14                                             I
                                                     I                                                                                        I
 NO OVER OR UNDER VOLTAGES                           I ADD      -.00360 P.U.SUSCEPTANCE AT BUS  7                                             I
                                                     I                                                                                        I
                                                                                                                                              I

                                  *BUS DATA
BUS IT          V1            V2             B           Q-MAX          Q-MIN
  1  3       1.06000        .00000        .00000      200.00000     -200.00000
  2  4        .20176       1.04500        .00000      200.00000     -200.00000
  3  4       1.03856       1.01000        .00000      200.00000     -200.00000
  4  0        .52700       -.04300        .00000      200.00000     -200.00000
  5  0        .06379        .01764        .00000      200.00000     -200.00000
  6  4        .12343       1.07000        .00000      200.00000     -200.00000
  7  0        .00000        .00000        .00000      200.00000     -200.00000
  8  4        .00000       1.09000        .00000      200.00000     -200.00000
  9  0        .32524        .18302        .00000      200.00000     -200.00000
 10  0        .09923        .06395        .00000      200.00000     -200.00000
 11  0        .03859        .01965        .00000      200.00000     -200.00000
 12  0        .06725        .01764        .00000      200.00000     -200.00000
 13  0        .14884        .06395        .00000      200.00000     -200.00000
 14  0        .16447        .05513        .00000      200.00000     -200.00000
  0  0        .00000        .00000        .00000      200.00000     -200.00000
------------------------------------------------------------------------ ------------------------------------------------------------------
YEAR 3


     THE BUS DATA FOR THIS YEAR ARE

      BUS  I    TYPE    I      VALUES IN P.U.   I      VALUES IN P.U. OR DEG.   I
     ------I------------I-----------------------I-------------------------------I
       1   I   SLACK    I  V-MAG=      1.06000  I  PHASE=      .00000           I
       2   I    P,V     I   P-IN=       .20176  I  V-MAG=     1.04500           I
       3   I    P,V     I   P-IN=      1.03856  I  V-MAG=     1.01000           I
       4   I    P,Q     I  P-OUT=       .52700  I  Q-OUT=     -.04300           I
       5   I    P,Q     I  P-OUT=       .06379  I  Q-OUT=      .01764           I
   6  I   P,V   I   P-IN*      .12348 I  V-MAG*    1.07060      I
   7  I   P,Q   I   P-OUT*     .00000 I  Q-OUT*     .00000      I
   8  I   P,V   I   P-IN*      .00000 I  V-MAG*    1.09060      I
   9  I   P,Q   I   P-OUT*     .32524 I  Q-OUT*     .18302      I
  10  I   P,Q   I   P-OUT*     .09923 I  Q-OUT*     .06395      I
  11  I   P,Q   I   P-OUT*     .03859 I  Q-OUT*     .01985      I
  12  I   P,Q   I   P-OUT*     .06725 I  Q-OUT*     .01764      I
  13  I   P,Q   I   P-OUT*     .14864 I  Q-OUT*     .06395      I
  14  I   P,Q   I   P-OUT*     .16427 I  Q-OUT*     .05513      I
------I---------I---------------------I-------------------------I

*********************************************
* OUTAGE IN BRANCH    * OVERLOAD IN BRANCH  *
*********************************************
*        6           *                      *
*        3           *                      *
*        8           *                      *
*        5           *


          ITERATION 1
                                                                                          I
                                             I                  CORRECTIVE MEASURE        I
          SYSTEM CONDITION                   I-------------------------------------------I
---------------------------------------------I                                            I
NO OVERLOADS IN YEAR  3 ITERATION  1         I                                            I
OVER VOLTAGE AT BUS  7 MAGNITUDE 1.07210     I ADD    -.02100 P.U.SUSCEPTANCE AT BUS  7   I
                                             I                                            I
UNDER VOLTAGE AT BUS 14 MAGNITUDE  .98466    I ADD     .00553 P.U.SUSCEPTANCE AT BUS 14   I
                                             I
NO OVER OR UNDER VOLTAGES


                                 *BUS DATA
BUS TY        V1           V2            R          Q-MAX         Q-MIN
  1  3      1.06000       .00000       .00000     200.00000    -200.00000
  2  4       .21185      1.04500       .00000     200.00000    -200.00000
  3  4      1.04048      1.01000       .00000     200.00000    -200.00000
  4  0       .55334      -.04515       .00000     200.00000    -200.00000
  5  0       .06798       .01852       .00000     200.00000    -200.00000
  6  4       .12965      1.07000       .00000     200.00000    -200.00000
  7  0       .00000       .00000       .00000     200.00000    -200.00000
  8  4       .00000      1.09000       .00000     200.00000    -200.00000
  9  0       .34150       .19217       .00000     200.00000    -200.00000
 10  0       .16419       .06714       .00000     200.00000    -200.00000
 11  0       .04052       .02084       .00000     200.00000    -200.00000
 12  0       .07062       .01652       .00000     200.00000    -200.00000
 13  0       .15623       .06714       .00000     200.00000    -200.00000
 14  0       .17249       .05768       .00000     200.00000    -200.00000
  3  0       .06000       .00000       .00000     200.00000    -200.00000
---------------------------------------------------------------------------
```

```
YEAR 4

     THE BUS DATA FOR THIS YEAR ARE

      BUS  I   TYPE   I     VALUES IN P.U.  I     VALUES IN P.U. OR DEG.  I
     ------I----------I---------------------I-----------------------------I
        1  I   SLACK  I  V-MAG=     1.06000 I  PHASE=       .00000        I
        2  I   P,V    I   P-IN=      .21185 I  V-MAG=      1.04500        I
        3  I   P,V    I   P-IN=     1.09048 I  V-MAG=      1.01000        I
        4  I   P,Q    I  P-OUT=      .55334 I  Q-OUT=      -.04515        I
        5  I   P,Q    I  P-OUT=      .08798 I  Q-OUT=       .01552        I
        6  I   P,V    I   P-IN=      .12965 I  V-MAG=      1.07000        I
        7  I   P,Q    I  P-OUT=      .00000 I  Q-OUT=       .00000        I
        8  I   P,V    I   P-IN=      .00000 I  V-MAG=      1.09000        I
        9  I   P,Q    I  P-OUT=      .34150 I  Q-OUT=       .19217        I
       10  I   P,Q    I  P-OUT=      .10419 I  Q-OUT=       .06714        I
       11  I   P,Q    I  P-OUT=      .04052 I  Q-OUT=       .02084        I
       12  I   P,Q    I  P-OUT=      .07062 I  Q-OUT=       .01552        I
       13  I   P,Q    I  P-OUT=      .15628 I  Q-OUT=       .06714        I
       14  I   P,Q    I  P-OUT=      .17249 I  Q-OUT=       .05788        I
     ------I----------I---------------------I-----------------------------I

     ********************************************
     * OUTAGE IN BRANCH     * OVERLOAD IN BRANCH   *
     ********************************************
     *        6            *                       *
     *        3            *                       *
     *        8            *                       *
     *        5            *                       *


          ITERATION 1

           SYSTEM CONDITION                         I                       CORRECTIVE MEASURE                         I
     -----------------------------------------------I-------------------------------------------------------------------I
     NO OVERLOADS IN YEAR  4 ITERATION  1           I                                                                   I
     UNDER VOLTAGE AT BUS 14 MAGNITUDE  .98279      I                                                                   I
                                                    I ADD      .00996 P.U.SUSCEPTANCE AT BUS 14                         I
     NO OVER OR UNDER VOLTAGES                      I                                                                   I
```

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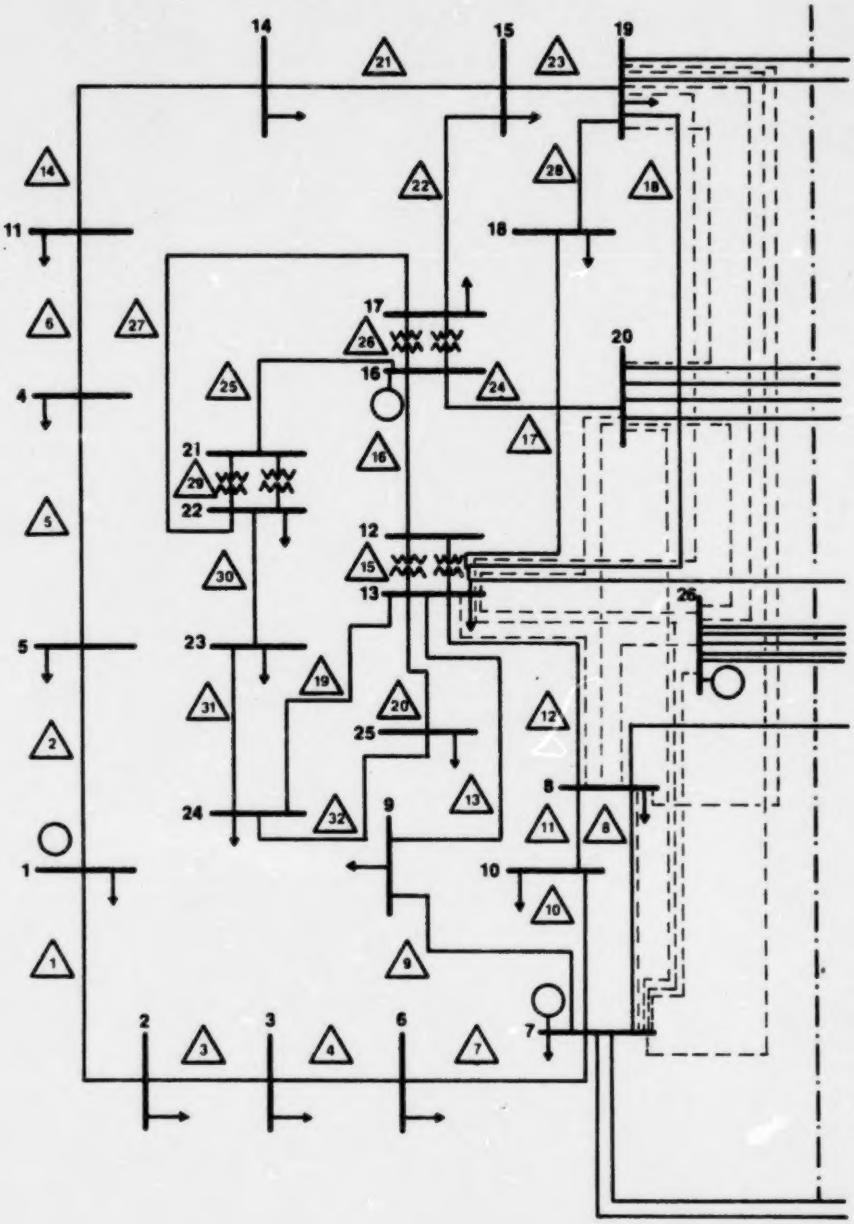
APPENDIX E

EXAMPLE PLANNING STUDY FOR THE WISCONSIN UPPER MICHIGAN SYSTEM NETWORK (AC MODEL)

The one-line diagram for the Wisconsin Upper Michigan System (WUMS) 26-bus reduced system is shown in Figure E-1, the new bus numbers are shown in Table C-1, Table E-1 shows the bus data, and Table E-2 shows the line data.

OUTPUT OF THE PLANNING PROGRAM (AC MODEL)

The output of the planning program for the WUMS network is shown in Figure E-2. The variable list is the same as that indicated in Appendix D.


14
15
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24
4
17
21
16
29
22
5
12
15
30
13
26
5
23
19
31
20
25
12
2
8
24
32
9
13
11
8
1
10
10
1
9
7
2
3
6
3
4
7

Figure E-1. The WUMS reduced AC model.

TABLE E-1. WUMS 26-BUS DATA

Bus number	Bus type	Voltage mag. p.u.	Voltage phase deg.	Generation p.u. MW	Load		Susceptance p.u. ohms
					p.u. MW	p.u. MVAR	
1	Generation	1.042		1.579			
2	Load				0.189	-0.004	
3	Load				0.146	0.043	
4	Load				0.193	0.007	
5	Load				0.076	0.053	0.02822
6	Load				0.356	-0.02	
7	Generation	1.02		0.60273			
8	Load				1.5428	0.05619	
9	Load				0.284	-0.025	
10	Load				0.106	0.074	0.02166
11	Load				0.31	-0.03	
12	Load				0	0	
13	Load				1.37148	-0.09903	
14	Load				0.367	-0.008	
15	Load				0.332	0.011	0.02725
16	Generation	1.021		5.142			
17	Load				0.275	0.085	
18	Load				0.217	0.092	
19	Load				1.67318	-0.14995	
20	Load				-0.13749	0.50817	
21	Load				0	0	
22	Load				0.868	-0.184	
23	Load				0.812	0.104	
24	Load				1.024	-0.144	
25	Load				0.128	0.039	
26	Slack	1.03	0				

TABLE E-2. WUMS 26-BUS NETWORK LINE DATA

From node	To node	Type[a]	Resistance p.u. ohms	Reactance p.u. ohms	Shunt susceptance[b] p.u. ohms	Flow rating MVA
1	2	1	0.0195	0.1120	0.0137	215.0000
1	5	1	0.0129	0.0739	0.0090	215.0000
2	3	1	0.0130	0.0752	0.0093	215.0000
3	6	1	0.0517	0.1109	0.0119	110.0000
4	5	1	0.0113	0.0653	0.0081	215.0000
4	11	1	0.0176	0.1013	0.0127	215.0000
6	7	1	0.0696	0.1487	0.0162	110.0000
7	8	1	0.0131	0.0401	0.0048	141.0000
7	8	1	0.1432	0.4507	0.0000	0.0000[c]
7	9	1	0.0157	0.0431	0.0026	141.0000
7	10	1	0.0116	0.0232	0.0053	110.0000
8	10	1	0.0087	0.0149	0.0015	110.0000
8	13	1	0.0304	0.0989	0.0113	127.0000
8	13	1	0.5417	1.3879	0.0000	0.0000[c]
9	13	1	0.0150	0.0762	0.0093	141.0000
11	14	1	0.0185	0.1062	0.0135	215.0000
13	12	2	0.0012	0.0515	1.0000	224.0000
13	12	2	0.0012	0.0515	1.0000	224.0000
12	16	1	0.0022	0.0327	0.1751	1108.0000
13	18	1	0.0380	0.1099	0.0137	141.0000
13	19	1	0.0533	0.1753	0.0202	129.0000
13	19	1	2.1464	4.1909	0.0000	0.0000[c]
13	24	1	0.0157	0.0936	0.0139	143.0000
13	25	1	0.0065	0.0389	0.0058	143.0000
14	15	1	0.0131	0.0750	0.0096	215.0000
15	17	1	0.0038	0.0240	0.0027	215.0000
15	19	1	0.0150	0.0886	0.0118	215.0000
16	20	1	0.0023	0.0348	0.1707	598.0000
16	21	1	0.0007	0.0109	0.0564	1303.0000
16	17	2	0.0014	0.0573	1.0000	200.0000
16	17	2	0.0013	0.0573	1.0000	200.0000

(continued)

TABLE E-2 (continued)

From node	To node	Type[a]	Resistance p.u. ohms	Reactance p.u. ohms	Shunt susceptance[b] p.u. ohms	Flow rating MVA
17	22	1	0.0103	0.0724	0.0085	287.0000
18	19	1	0.0192	0.0585	0.0073	141.0000
21	22	2	0.0000	0.0500	1.0000	224.0000
21	22	2	0.0000	0.0500	1.0000	224.0000
22	23	1	0.0112	0.0738	0.0103	270.0000
23	24	1	0.0068	0.0419	0.0088	270.0000
24	25	1	0.0110	0.0585	0.0060	240.0000
20	7	1	0.0098	0.2234	0.0000	0.0000[c]
20	8	1	0.0924	0.3081	0.0000	0.0000[c]
20	13	1	0.0402	0.3208	0.0000	0.0000[c]
20	19	1	0.0326	0.1281	0.0000	0.0000[c]
20	25	1	0.0058	0.1263	0.0000	0.0000[c]
26	7	1	0.0239	0.3741	0.0000	0.0000[c]
26	8	1	0.3961	1.4434	0.0000	0.0000[c]
26	13	1	0.1637	1.7919	0.0000	0.0000[c]
26	19	1	0.4097	1.3078	0.0000	0.0000[c]
19	7	1	1.4231	3.5847	0.0000	0.0000[c]
19	8	1	3.1958	4.3702	0.0000	0.0000[c]
13	7	1	0.1854	1.3556	0.0000	0.0000[c]

[a] Type 1 = Transmission Line
2 = Transformer

[b] Tap setting for transformers.

[c] Indicates artificial lines created during the network reduction.

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```
GENERAL DATA

LIMIT  IPEN   NODE   YEARS       ETA      MVA-BASE     NSUB      V-MAX         V-MIN    IOUTLR
  20     1     26      2      .07152    100.00000       5      1.10000        .96000         4


                                 *BUS DATA
BUS TY       V1          V2           B          Q-MAX        Q-MIN
  1  4   1.57900     1.04200      .00000    400.00000   -400.00000
  2  0    .16900     -.00400      .00000       .00000       .00000
  3  0    .14600      .04300      .00000       .00000       .00000
  4  0    .19300      .00700      .00000       .00000       .00000
  5  0    .07600      .05300      .02822       .00000       .00000
  6  0    .35600     -.02000      .00000       .00000       .00000
  7  4   -.60273     1.02000      .00000    400.00000   -400.00000
  8  0   1.54280      .05619      .00000       .00000       .00000
  9  0    .26400     -.05200      .00000       .00000       .00000
 10  0    .10600      .07400      .02166       .00000       .00000
 11  0    .31000     -.03000      .00000       .00000       .00000
 12  0    .00000      .00000      .00000       .00000       .00000
 13  0   1.37148     -.09903      .00000       .00000       .00000
 14  0    .36700     -.00800      .00000       .00000       .00000
 15  0    .33200      .01100      .02725       .00000       .00000
 16  4   5.14200     1.02100      .00000    400.00000   -400.00000
 17  0    .27500      .08500      .00000       .00000       .00000
 18  0    .21700      .09200      .00000       .00000       .00000
 19  0   1.67318     -.14795      .00000       .00000       .00000
 20  0   -.13749      .50817      .00000       .00000       .00000
 21  0    .00000      .00000      .00000       .00000       .00000
 22  0    .36800     -.18400      .00000       .00000       .00000
 23  0    .81200      .10400      .00000     25.00000      5.00000
 24  0   1.02400     -.14400      .00000       .00000       .00000
 25  0    .12500      .03900      .00000       .00000       .00000
 26  3   1.03000      .00000      .00000       .00000       .00000
  0  0    .00000      .00000      .00000       .00000       .00000


                                 *LINE DATA
 NS  NR K         R          X          YS       POMAX       ENCO        CAPCO         BRANCH
  1   2 1     .01950      .11200     .01367   215.00000     1.00000 64800.00000          1
  1   5 1     .01290      .07390     .00902   215.00000     1.00000 64800.00000          2
  2   3 1     .01300      .07520     .00931   215.00000     1.00000 64800.00000          3
  3   6 1     .05170      .11090     .01192   110.00000     1.00000 64800.00000          4
  4   5 1     .01130      .06530     .00810   215.00000     1.00000 64800.00000          5
  4  11 1     .01760      .10130     .01273   215.00000     1.00000 64800.00000          6
  6   7 1     .06960      .14870     .01622   110.00000     1.00000 64800.00000          7
  7   8 1     .01310      .04010     .00479   141.00000     1.00000 64800.00000          8
  7   8 1     .14322      .45367     .00000      .00000    -1.00000-64800.00000          8
  7   9 1     .01570      .04310     .00579   141.00000     1.00000 64800.00000          9
  7  10 1     .01160      .02320     .00256   110.00000     1.00000 64800.00000         10
  6  10 1     .00870      .01490     .00147   110.00000     1.00000 64800.00000         11
  8  13 1     .03040      .09390     .01126   127.00000     1.00000 64800.00000         12
```

Figure E-2. Output of the planning program, WUMS reduced AC model.

```
 8  11 1     .34167     1.38799      .00000      .00000   -1.00000-64800.00000      12
 9  11 1     .01500      .07420      .00930   161.00000    1.00000 64800.00000      13
11  14 1     .01850      .10420      .01351   215.00000    1.00000 64800.00000      14
13  12 2     .00120      .05150     1.00000   224.00000    1.00000 64800.00000      15
13  12 2     .00120      .05150     1.00000   224.00000    1.00000 64800.00000      15
12  16 1     .00220      .03270      .17510  1108.00000    1.00000 64800.00000      16
13  18 1     .03600      .10990      .01372   141.00000    1.00000 64800.00000      17
13  19 1     .05330      .17530      .02022   129.00000    1.00000 64800.00000      18
13  19 1    2.14643     4.19086      .00000      .00000   -1.00000-64800.00000      18
13  24 1     .01570      .09360      .01395   143.00000    1.00000 64800.00000      19
13  25 1     .00650      .03890      .00580   143.00000    1.00000 64800.00000      20
14  15 1     .01310      .07500      .00965   215.00000    1.00000 64800.00000      21
15  17 1     .00380      .02400      .00275   215.00000    1.00000 64800.00000      22
15  19 1     .01500      .09860      .01177   215.00000    1.00000 64800.00000      23
16  20 1     .00230      .03480      .17075   598.00000    1.00000 64800.00000      24
16  21 1     .00070      .01090      .05641  1303.00000    1.00000 64800.00000      25
16  17 2     .00140      .05730     1.00000   200.00000    1.00000 64800.00000      26
16  17 2     .00135      .05730     1.00000   200.00000    1.00000 64800.00000      26
17  22 1     .01030      .07240      .00653   287.00000    1.00000 64800.00000      27
18  19 1     .01920      .05650      .00734   141.00000    1.00000 64800.00000      28
21  22 2     .00000      .05000     1.00000   224.00000    1.00000 64800.00000      29
21  22 2     .00000      .05000     1.00000   224.00000    1.00000 64800.00000      29
22  23 1     .01120      .07380      .01028   270.00000    1.00000 64800.00000      30
23  24 1     .00660      .04190      .00664   270.00000    1.00000 64800.00000      31
24  25 1     .01100      .05650      .00631   240.00000    1.00000 64800.00000      32
20   7 1     .00983      .22340      .00000      .00000   -1.00000-64800.00000      33
20   8 1     .09240      .30815      .00000      .00000   -1.00000-64800.00000      34
20  13 1     .04024      .32076      .00000      .00000   -1.00000-64800.00000      35
20  19 1     .03264      .12810      .00000      .00000   -1.00000-64800.00000      36
20  26 1     .00585      .12626      .00000      .00000   -1.00000-64800.00000      37
26   7 1     .02394      .37415      .00000      .00000   -1.00000-64800.00000      38
26   8 1     .39610     1.44345      .00000      .00000   -1.00000-64800.00000      39
26  13 1     .16375     1.79189      .00000      .00000   -1.00000-64800.00000      40
26  19 1     .40968     1.30783      .00000      .00000   -1.00000-64800.00000      41
19   7 1    1.42308     3.58472      .00000      .00000   -1.00000-64800.00000      42
19   8 1    3.19585     4.37025      .00000      .00000   -1.00000-64800.00000      43
13   7 1     .18539     1.35563      .00000      .00000   -1.00000-64800.00000      44
```

```
BASE CASE LOAD FLOW RESULTS

BUS    VOLTAGE MAG.    PHASE-DEGREES
-------------------------------------
  1        1.04200       -12.12125
  2        1.03129       -16.68911
  3        1.02755       -19.34290
  4        1.02432       -17.65933
  5        1.03076       -15.17629
  6        1.01636       -22.30682
  7        1.02000       -23.19696
  8        1.00750       -23.94078
```

```
      9          1.01491      -23.69788
     10          1.01172      -23.69304
     11          1.01986      -20.46552
     12          1.01579      -20.46668
     13          1.01221      -23.33180
     14          1.01420      -21.55158
     15          1.01353      -20.76504
     16          1.02100      -16.64821
     17          1.01796      -19.33992
     18           .99812      -23.65369
     19           .99900      -23.48388
     20          1.00927      -16.43573
     21          1.02006      -17.89447
     22          1.02949      -20.29237
     23          1.00578      -24.78998
     24          1.00791      -25.48338
     25          1.00939      -24.36542
     26          1.03000         .00000
------------------------------------------
--------------------------------------------------------- ----------------------------------------------------------

YEAR 1


     THE BUS DATA FOR THIS YEAR ARE

      BUS  I   TYPE   I      VALUES IN P.U.   I      VALUES IN P.U. OR DEG.   I
     ------I----------I---------------------I------------------------------I
        1  I    P,V   I   P-IN=     1.57900 I  V-MAG=      1.04200          I
        2  I    P,Q   I  P-OUT=      .18900 I  Q-OUT=      -.00400          I
        3  I    P,Q   I  P-OUT=      .14600 I  Q-OUT=       .04300          I
        4  I    P,Q   I  P-OUT=      .19300 I  Q-OUT=       .00700          I
        5  I    P,Q   I  P-OUT=      .07600 I  Q-OUT=       .05300          I
        6  I    P,Q   I  P-OUT=      .35600 I  Q-OUT=      -.02000          I
        7  I    P,V   I   P-IN=    -.60273 I  V-MAG=      1.02000          I
        8  I    P,Q   I  P-OUT=     1.54280 I  Q-OUT=       .05619          I
        9  I    P,Q   I  P-OUT=      .28400 I  Q-OUT=      -.05200          I
       10  I    P,Q   I  P-OUT=      .10600 I  Q-OUT=       .07400          I
       11  I    P,Q   I  P-OUT=      .31000 I  Q-OUT=      -.03060          I
       12  I    P,Q   I  P-OUT=      .00000 I  Q-OUT=       .00000          I
       13  I    P,Q   I  P-OUT=     1.37148 I  Q-OUT=      -.09907          I
       14  I    P,Q   I  P-OUT=      .36700 I  Q-OUT=      -.00860          I
       15  I    P,Q   I  P-OUT=      .73200 I  Q-OUT=       .01160          I
       16  I    P,V   I   P-IN=     5.14200 I  V-MAG=      1.02100          I
       17  I    P,Q   I  P-OUT=      .27500 I  Q-OUT=       .08500          I
       18  I    P,Q   I  P-OUT=      .21700 I  Q-OUT=       .09260          I
       19  I    P,Q   I  P-OUT=     1.67318 I  Q-OUT=      -.14995          I
       20  I    P,Q   I  P-OUT=     -.13749 I  Q-OUT=       .50817          I
       21  I    P,Q   I  P-OUT=      .00000 I  Q-OUT=       .00000          I
       22  I    P,Q   I  P-OUT=      .26800 I  Q-OUT=      -.16400          I
       23  I    P,Q   I  P-OUT=      .81200 I  Q-OUT=       .10400          I
       24  I    P,Q   I  P-OUT=     1.02400 I  Q-OUT=      -.14400          I
       25  I    P,Q   I  P-OUT=      .12800 I  Q-OUT=       .03900          I
       26  I   SLACK  I  V-MAG=     1.03000 I  PHASE=       .00000          I
     ------I----------I---------------------I------------------------------I
```

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```
****************************************************
* OUTAGE IN BRANCH      * OVERLOAD IN BRANCH       *
****************************************************
*          30           *                          *
*           1           *                          *
*          16           *                          *
*           4           *                          *


                ITERATION 1

            SYSTEM CONDITION                     I                     CORRECTIVE MEASURE                              I
-------------------------------------------------I---------------------------------------------------------------------I
NO OVERLOADS IN YEAR  1 ITERATION  1             I                                                                     I
UNDER VOLTAGE AT BUS  2 MAGNITUDE  .95107        I                                                                     I
UNDER VOLTAGE AT BUS  3 MAGNITUDE  .95163        I                                                                     I
                                                 I ADD      .00742 P.U.SUSCEPTANCE AT BUS  2                           I
                                                 I ADD      .05731 P.U.SUSCEPTANCE AT BUS  3                           I
NO OVER OR UNDER VOLTAGES                        I                                                                     I


                              *BUS DATA
BUS TY        V1           V2             B        Q-MAX        Q-MIN
  1  4     1.57900      1.04200       .00000   400.00000   -400.00000
  2  0      .26036      -.00424       .00000      .00000       .00000
  3  0      .15476       .04558       .00000      .00000       .00000
  4  0      .20459       .00742       .00000      .00000       .00000
  5  0      .06056       .05618       .02822      .00000       .00000
  6  0      .37736      -.02120       .00000      .00000       .00000
  7  4     -.60273      1.02000       .00000   400.00000   -400.00000
  8  0     1.63537       .05956       .00000      .00000       .00000
  9  0      .36106      -.55512       .00000      .00000       .00000
 10  0      .11236       .07466       .02166      .00000       .00000
 11  0      .32860      -.03160       .00000      .00000       .00000
 12  0      .00000       .00000       .00000      .00000       .00000
 13  0     1.45377      -.10497       .00000      .00000       .00000
 14  0      .36902      -.00848       .00000      .00000       .00000
 15  0      .35172       .01166       .02725      .00000       .00000
 16  4    10.26000      1.02100       .00000   400.00000   -400.00000
 17  0      .29150       .09010       .00000      .00000       .00000
 18  0      .23002       .09752       .00000      .00000       .00000
 19  0     1.77357      -.15895       .00000      .00000       .00000
 20  0     -.14574       .53866       .00000      .00000       .00000
 21  0      .00000       .00000       .00000      .00000       .00000
 22  0      .92008      -.19564       .00000      .00000       .00000
 23  0      .86072       .11024       .00000    25.00000      5.00000
 24  0     1.06544      -.15264       .00000      .00000       .00000
 25  0      .13568       .04136       .00000      .00000       .00000
 26  3     1.03000       .00000       .00000      .00000       .00000
  C  0      .00000       .00000       .00000      .00000       .00000
--------------------------------------------------------------- ------------------------------------------
```

```
YEAR 2

THE BUS DATA FOR THIS YEAR ARE

  BUS  I    TYPE    I      VALUES IN P.U.    I     VALUES IN P.U. OR DEG.   I
-------I------------I------------------------I------------------------------I
   1   I    P,V     I   P-IN=      1.57900   I  V-MAG=      1.04200          I
   2   I    P,Q     I  P-OUT=       .20034   I  Q-OUT=      -.00424          I
   3   I    P,Q     I  P-OUT=       .15476   I  Q-OUT=       .04558          I
   4   I    P,Q     I  P-OUT=       .20458   I  Q-OUT=       .00742          I
   5   I    P,Q     I  P-OUT=       .86056   I  Q-OUT=       .05618          I
   6   I    P,Q     I  P-OUT=       .37736   I  Q-OUT=      -.02120          I
   7   I    P,V     I   P-IN=      -.60273   I  V-MAG=      1.02000          I
   8   I    P,Q     I  P-OUT=      1.63537   I  Q-OUT=       .05956          I
   9   I    P,Q     I  P-OUT=       .90104   I  Q-OUT=      -.05517          I
  10   I    P,Q     I  P-OUT=       .11236   I  Q-OUT=       .07866          I
  11   I    P,Q     I  P-OUT=       .32860   I  Q-OUT=      -.03160          I
  12   I    P,Q     I  P-OUT=       .00000   I  Q-OUT=       .00000          I
  13   I    P,Q     I  P-OUT=      1.45377   I  Q-OUT=      -.10497          I
  14   I    P,Q     I  P-OUT=       .36902   I  Q-OUT=      -.00948          I
  15   I    P,Q     I  P-OUT=       .35192   I  Q-OUT=       .01166          I
  16   I    P,V     I   P-IN=     10.28000   I  V-MAG=      1.02100          I
  17   I    P,Q     I  P-OUT=       .29150   I  Q-OUT=       .09019          I
  18   I    P,Q     I  P-OUT=       .23002   I  Q-OUT=       .04752          I
  19   I    P,Q     I  P-OUT=      1.77357   I  Q-OUT=      -.15895          I
  20   I    P,Q     I  P-OUT=      -.14574   I  Q-OUT=       .53866          I
  21   I    P,Q     I  P-OUT=       .00000   I  Q-OUT=       .00000          I
  22   I    P,Q     I  P-OUT=       .92008   I  Q-OUT=      -.19504          I
  23   I    P,Q     I  P-OUT=       .86072   I  Q-OUT=       .11024          I
  24   I    P,Q     I  P-OUT=      1.08544   I  Q-OUT=      -.15264          I
  25   I    P,Q     I  P-OUT=       .13568   I  Q-OUT=       .04136          I
  26   I   SLACK    I  V-MAG=      1.03000   I  PHASE=       .00000          I
-------I------------I------------------------I------------------------------I
```

```
**************************************************
* OUTAGE IN BRANCH      * OVERLOAD IN BRANCH     *
**************************************************
*       16              *                        *
*                       *          22            *
*                       *                        *
*                       *                        *
*                       *                        *
*                       *                        *
*                       *                        *
*                       *                        *
*                       *                        *
*                       *                        *
*                       *                        *
*                       *                        *
*                       *                        *
*                       *                        *
*                       *                        *
*                       *                        *
```

```
*********************************************
*     INTERMEDIATE LOAD FLOW RESULTS        *
*       FOR OUTAGE IN BRANCH  16            *
* BUS     VOLT. P.U.       ANGLE DEG.       *
*********************************************
*  1        1.04200          9.73276        *
*  2        1.03364          3.61058        *
*  3        1.03401           .30808        *
*  4        1.02573          5.89109        *
*  5        1.03309          7.55115        *
*  6        1.01825         -3.48363        *
*  7        1.02000         -6.29050        *
*  8        1.00416         -6.86676        *
*  9        1.01097         -6.53927        *
* 10        1.00479         -6.89724        *
* 11        1.01746          4.42847        *
```

```
•  • 12         1.00049          -3.44276   •
•  • 13          .99428          -3.73575   •
•  • 14         1.06897           6.87846   •
•  • 15         1.00628           6.87036   •
•  • 16         1.02100          15.10150   •
•  • 17         1.01376          10.23079   •
•  • 18          .96576          -3.51115   •
•  • 19          .99013          -1.61611   •
•  • 20         1.00252           6.67097   •
•  • 21         1.01620          13.28452   •
•  • 22         1.01249           9.06064   •
•  • 23          .96455          -1.01247   •
•  • 24          .96856          -4.76126   •
•  • 25          .94176          -5.51929   •
•  • 26         1.03000            .00000   •
•
•
•
•  ****************************************
•  •     INTERMEDIATE LOAD FLOW RESULTS     •
•  •        FOR OUTAGE IN BRANCH  24        •
•  • BUS     VOLT. P.U.      ANGLE DEG.     •
•  ****************************************
•  •   1        1.04200          16.50126   •
•  •   2        1.03385          10.38418   •
•  •   3        1.03401           7.08511   •
•  •   4        1.02620          12.45033   •
•  •   5        1.03328          14.31438   •
•  •   6        1.01826           2.89901   •
•  •   7        1.04000            .49971   •
•  •   8        1.00662            .23213   •
•  •   9        1.01770           2.26927   •
•  •  10        1.01121            .27930   •
•  •  11        1.01828          11.18144   •
•  •  12        1.00456          11.38733   •
•  •  13        1.00842           6.57993   •
•  •  14        1.01015          11.42194   •
•  •  15        1.00779          13.60278   •
•  •  16        1.02100          21.95769   •
•  •  17        1.01509          17.13705   •
•  •  18         .99332           4.75140   •
•  •  19         .99451           4.45968   •
•  •  20         .99720           2.86321   •
•  •  21        1.01806          20.94022   •
•  •  22        1.01722          16.60868   •
•  •  23         .99754           8.73649   •
•  •  24        1.00173           6.23901   •
•  •  25        1.00450           6.26896   •
•  •  26        1.03000            .00000   •
•
•
•
•  ****************************************
•  •     INTERMEDIATE LOAD FLOW RESULTS     •
•  •        FOR OUTAGE IN BRANCH  15        •
```

```
15
22

15

24

30
22
23
15
```

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```
*                              *                                  *   * BUS     VOLT. P.U.      ANGLE DEG.   *
*                              *                                  *   *****************************************
*                              *                                  *   *  1       1.04260         8.91028     *
*                              *                                  *   *  2       1.03457         3.76011     *
*                              *                                  *   *  3       1.03412          .44289     *
*                              *                                  *   *  4       1.02719         4.73930     *
*                              *                                  *   *  5       1.03357         6.74275     *
*                              *                                  *   *  6       1.01898        -3.12032     *
*                              *                                  *   *  7       1.02000        -4.67665     *
*                              *                                  *   *  8       1.00764        -5.15957     *
*                              *                                  *   *  9       1.01734        -4.75502     *
*                              *                                  *   * 10       1.01128        -5.02488     *
*                              *                                  *   * 11       1.02094         2.33936     *
*                              *                                  *   * 12       1.01279         5.27718     *
*                              *                                  *   * 13       1.01073        -2.24456     *
*                              *                                  *   * 14       1.01463         2.20790     *
*                              *                                  *   * 15       1.01352         3.76358     *
*                              *                                  *   * 16       1.02100        10.00673     *
*                              *                                  *   * 17       1.01206         6.25869     *
*                              *                                  *   * 18        .99880        -2.49074     *
*                              *                                  *   * 19       1.00140        -1.93613     *
*                              *                                  *   * 20       1.01054         4.35570     *
*                              *                                  *   * 21       1.01907         8.59891     *
*                              *                                  *   * 22       1.01924         5.76293     *
*                              *                                  *   * 23       1.00149        -1.39774     *
*                              *                                  *   * 24       1.00500        -3.26743     *
*                              *                                  *   * 25       1.00725        -2.83068     *
*       1                      *                                  *   * 26       1.03000          .00000     *
*       4                      *                                  *
*      26                      *                                  *
*      12                      *                                  *


        ITERATION 1

             SYSTEM CONDITION                    I                          CORRECTIVE MEASURE                                  I
-------------------------------------------------I----------------------------------------------------------------------------I
 OVER LOAD IN BRANCH 15 BETWEEN BUSES 13 AND 12 I                                                                             I
 OVER LOAD IN BRANCH 22 BETWEEN BUSES 15 AND 17 I                                                                             I
                                                 I MIN  .9954+01 P.U. SUSCEPTANCE I[illegible]RANCH 15 BETWEEN BUSES 13 AND 12    I
                                                 I ADD 1 LINE OF TYPE  1 IN BRANCH 1[illegible] WHOSE R AND X ARE   .00120   .05150


*************************************************
* OUTAGE IN BRANCH      * OVERLOAD IN BRANCH    *
*************************************************
*        16             *                       *
*                       *          22           *
*                       *                       *     ****************************************
*                       *                       *     *      INTERMEDIATE LOAD FLOW RESULTS  *
*                       *                       *     *        FOR OUTAGE IN BRANCH  16      *
```

```
24

22

* BUS        VOLT. P.U.         ANGLE DEG.    *
*************************************************
*   1         1.04200            9.73006     *
*   2         1.03384            3.60786     *
*   3         1.03401             .30534     *
*   4         1.02573            5.88842     *
*   5         1.03303            7.54847     *
*   6         1.01825           -3.86639     *
*   7         1.02000           -6.29328     *
*   8         1.00414           -6.86960     *
*   9         1.01097           -6.54228     *
*  10         1.00979           -6.70010     *
*  11         1.01746            4.42582     *
*  12          .99935           -5.57047     *
*  13          .99628           -5.73920     *
*  14         1.00897            4.87583     *
*  15         1.00628            6.86794     *
*  16         1.02100           15.09902     *
*  17         1.01376           10.22823     *
*  18          .96571           -3.51416     *
*  19          .99013           -1.61889     *
*  20         1.00252            6.66872     *
*  21         1.01620           13.26201     *
*  22         1.01269            9.05802     *
*  23          .96455           -1.01548     *
*  24          .96856           -4.76507     *
*  25          .99174           -5.52265     *
*  26         1.03000             .00000     *


*************************************************
*      INTERMEDIATE LOAD FLOW RESULTS           *
*        FOR OUTAGE IN BRANCH   24              *
* BUS       VOLT. P.U.         ANGLE DEG.       *
*************************************************
*   1         1.04200           16.14200     *
*   2         1.03403           10.14548     *
*   3         1.03407            6.92771     *
*   4         1.02653           12.13694     *
*   5         1.03341           13.27358     *
*   6         1.01845            2.87407     *
*   7         1.02000             .65373     *
*   8         1.00708             .79329     *
*   9         1.01864            2.45553     *
*  10         1.01148             .43799     *
*  11         1.01903           10.55427     *
*  12         1.00723           11.60176     *
*  13         1.01090            6.82317     *
*  14         1.01140           10.87123     *
*  15         1.00921           12.75917     *
*  16         1.02100           20.67333     *
*  17         1.01597           16.09394     *
*  18          .99526            4.71386     *
*  19          .99626            4.26739     *
*  20          .99821            2.90779     *
*  21         1.01855           19.13319     *
*  22         1.01834           15.58707     *
```

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```
                                                      *    * 23        1.00028        8.29795   *
                              *                       *    * 24        1.00441        6.15018   *
  *                           *                       *    * 25        1.00709        6.17052   *
  *                           *                       *    * 26        1.03000         .00000   *
  *                           *                       *
  *          30               *                       *
  *          22               *                       *
  *          23               *                       *
  *           1               *


         ITERATION 2
                                                                                                                  I
                                                                      CORRECTIVE MEASURE                           --------I
         SYSTEM CONDITION                        I                                                                 I
-------------------------------------------------I-------------------------------------------------------------   I
OVER LOAD IN BRANCH 22 BETWEEN BUSES 15 AND 17   I MIN  .7123+01 P.U. SUSCEPTANCE IN BRANCH 22 BETWEEN BUSES 15 AND 17   I
                                                 I ADD 1 LINE OF TYPE  1 IN BRANCH 22 WHOSE R AND X ARE   .00380   .02400


**************************************************
* OUTAGE IN BRANCH      * OVERLOAD IN BRANCH     *
**************************************************
*         16            *                        *
*         24            *                        *
*         30            *                        *
*         23            *


         ITERATION 3
                                                                                                                  I
                                                                      COPRECTIVE MEASURE                           --------I
         SYSTEM CONDITION                        I                                                                 I
-------------------------------------------------I-------------------------------------------------------------   I
NO OVERLOADS IN YEAR  2 ITERATION  3             I
NO OVER OR UNDER VOLTAGES                        I
```

APPENDIX F

LISTING OF THE PLANNING PROGRAM FOR THE DC MODEL

This Appendix describes the input and output data and lists the program (Figure F-1) for the DC power flow model.

INPUT AND OUTPUT DATA

The input data for this program is as follows:

(1) General information card: LIMIT, NODE, NYEAR, ETA, MVAB, NSUB, IOUTER, where LIMIT = maximum number of iterations allowed, NODE = number of nodes in the system -1, NYEAR = number of planning periods, ETA = yearly cost (in dollars) of one per-unit power loss, MVAB = base power in MW, NSUB = number of planning periods after which line removals should be considered, and IOUTER = stopping criterion for the automatic contingency selection subroutine (default value is 3);

(2) Branch data: NS, NR, R, X, POMAX, TAP, ENCO, CAPCO, followed by a zero card (0 0 0. 0. 0. 0. 0. 0.), where NS = origin node of the branch, NR = terminal node of the branch, R = series resistance in per unit, X = series reactance in per unit, POMAX = flow rating of the element in MW, TAP = transformer tap position, ENCO = yearly environmental cost in dollars of adding one per unit of capacity on the branch, and CAPCO = yearly capital costs (in dollars, fixed charges) of adding one per unit of capacity on the branch; and

(3) Bus data (NODE of them for every planning period): P, where P = real power injection in MW at the bus.

The output of the planning program is discussed in Appendix B.

```
C     THIS PROGRAM IS THE LAST VERSION OF THE PLANNING PROGRAM USING
C     DC LOAD FLOW
C   . IT TAKES INTO ACCOUNT REMOVAL OF LINES AFTER THEY HAVE BEEN ADDED
C     IT ALSO UTILIZES  A MODIFIED VERSION OF THE OUTAGE TEST SUBROUTINE
C     THAT USES THE SENSITIVITY MATRIX
C     TRANSMISSION NETWORK EXPANSION PROGRAM
C     THE INPUT DATA ARE
C           LIMIT,NODE,NYEAR,ETA,MVAB,NSUB,IOUTER
C                  WHERE, LIMIT  IS THE MAX, NO. OF ITERATIONS ALLOWED
C                  NODE  IS THE NUMBER OF BISSES IN THE SYSTEM -SLACK
C                  NYEAR  IS THE NUMBER OF YEARS OF STUDY
C                  ETA  IS THE COST OF ONE PER UNIT MW LOST POWER
C                  MVAB  IS THE BASE POWER
C                  NSUB  IS THE NO. OF YEARS AFTER WHICH WE CAN REMOVE LINES
C                  IOUTER  IS THE STOPPING CRITERION FOR OUTAGE TESTS
C      CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
C           NS,NR,R,X,POMAX,TAP,ENCO,CAPCO
C        WHERE,
C                  NS  IS THE ORIGIN OF THE BRANCH
C                  NR  IS THE TERMINAL NODE OF THE BRANCH
C                  R  IS THE PER UNIT RESISTANCE
C                  X  IS THE PER UNIT REACTANCE
C                  POMAX IS THE POWER RATING OF THE LINE IN ACTUAL
C                  MEGA WATTS
C                  TAP IS THE TRANSFORMER TAP RATIO. FOR LINES IT
C                  IS SET EQUAL TO ZERO
C                  ENCO IS THE ENVIRONMENTAL COST OF THE BRANCH
C                  CAPCO IS THE CAPITAL COST INSTALLMENTS FOR
C                  ADDING ONE PER UNIT OF CAPACITY TO THE BRANCH
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
C           P(I)
C             WHERE,
C                  P(I) IS THE NET REAL POWER INJECTION AT EACH NODE
CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
      PARAMETER ND=25,NB=58
      COMMON NODE,NBRA,ETA,P(ND),PF(ND),GAMAB(NB),B(NB,NB),PSI(NB),
     *PSTAR(NB),PHMIN(NB),GMAX(NB),COST(NB),A(NB,ND),GI(ND,ND),ITEMP(NB)
     *,ITER,TYPE(NB,4),EN(NB),CA(NB),MVAB
      COMMON AMC(NB),AD1(NB),IAD(NB)
      COMMON GARB(NB)
      READ,LIMIT,NODE,NYEAR,ETA,MVAB,NSUB,IOUTER
C     INITIALIZING THE ARRAYS
      DO 406 I=1,NB
      DO 407 J=1,4
      TYPE(I,J)=0.
 407  CONTINUE
 406  CONTINUE
      DO 102 I=1,NODE
      P(I)=0.
      PF(I)=0.
102   CONTINUE
      DO 104 I=1,NB
      AD1(I)=0.
      IAD(I)=0
      GAMAB(I)=0.
      PSI(I)=0.
      PHMIN(I)=1E-6
      GMAX(I)=0.
```

Figure F-1. Listing of planning program using DC load-flow.

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```
      COST(I)=0.
      EN(I)=0.
      CA(I)=0.
      AMU(I)=0.
      DO 103 J=1,NB
      B(I,J)=0.
103   CONTINUE
104   CONTINUE
      DO 106 I=1,NODE
      DO 105 J=1,NODE
      GI(I,J)=0.
105   CONTINUE
106   CONTINUE
      DO 108 I=1,NB
      DO 107 J=1,NODE
      A(I,J)=0.
107   CONTINUE
108   CONTINUE
C     SIMULATION OF THE NETWORK
      NSIND=9000
      NRIND=NSIND
      ICOUNT=0
      I=0
      RTOX=0.
 109  READ,NS,NR,R,X,POMAX,TAP,ENCO,CAPCO
      IF(NS.EQ.0.AND.NR.EQ.0)GO TO 4
      IF(TAP.EQ.0.)GO TO 231
      R=TAP*R
      X=TAP*X
 231  IF(NS.NE.NSIND.OR.NR.NE.NRIND)GO TO 200
      IF(ENCO.LT.0.)GO TO 201
      ICOUNT=ICOUNT+1
 201  CONTINUE
      ALF=X/(R**2+X**2)
      POMAX=POMAX/FLOAT(MVAB)
      IF(ENCO.LT.0.)GO TO 233
      RTOX=RTOX+R/X
233   CONTINUE
C     CHECK FOR ARTIFICIAL LINES
      IF(POMAX.LT.1E-5)GO TO 232
      PEMAX=POMAX/ALF
      IF(PHMAX.LT.PHMIN(I))PHMIN(I)=PHMAX
232   CONTINUE
      IF(ENCO.LT.0.)GO TO 234
      IF(ALF.GT.GMAX(I))GMAX(I)=ALF
234   CONTINUE
      GAMAB(I)=GAMAB(I)+ALF
C     THE FOLLOWING ARE NEEDED TO CONSTRUCT THE TYPE ARRAY
 420  DO 410 L=1,4
      IF(TYPE(I,L).EQ.0.)GO TO 240
      IF(ENCO.LT.0.)GO TO 109
      IF(ABS(1-ALF/TYPE(I,L)).LT.1E-4)GO TO 241
 410  CONTINUE
      WRITE(6,415)I
 415  FORMAT(/,'**MORE THAN 4 LINE TYPES IN BRANCH',I4,',CHANGE STATMENT
     * NUMBER 420 AND DIMENSION STATMENT',/)
      GO TO 241
 240  TYPE(I,L)=ALF
 241  CONTINUE
      GO TO 109
 200  NSIND=NS
      NRIND=NR
      I=I+1
      IF(ENCO.LT.0.)GO TO 237
      EN(I)=ENCO
      CA(I)=CAPCO
      GO TO 238
237   EN(I)=1E+8
      CA(I)=1E+8
238   CONTINUE
C     FORMATION OF THE INCIDENCE MATRIX
      IF(NS.EQ.0)GO TO 1
      A(I,NS)=1.
 1    CONTINUE
      IF(NR.EQ.0)GO TO 2
      A(I,NR)=-1.
 2    CONTINUE
      IF(I.EQ.1)GO TO 220
      KI=I-1
      AMU(KI)=RTOX/ICOUNT
      RTOX=0.
      ICOUNT=1
      GO TO 201
 220  ICOUNT=1
      GO TO 201
4     CONTINUE
      AMU(I)=RTOX/ICOUNT
      RTOX=0.
      NBRA=I
      WRITE(6,501)
 501  FORMAT(///,' ************************************************')
      WRITE(6,502)
 502  FORMAT(///,20X,' GENERAL INFORMATION')
      WRITE(6,503)NODE
 503  FORMAT(//,' TOTAL NUMBER OF BUSES(NOT INCLUDING SLACK BUS)=',I3)
      WRITE(6,504)NBRA
 504  FORMAT(/,' TOTAL NUMBER OF BRANCHES=',I3)
      WRITE(6,505)NYEAR
 505  FORMAT(/,' NUMBER OF YEARS OF STUDY=',I3)
      WRITE(6,506)ETA
 506  FORMAT(/,' COST OF ONE P.U. OF POWER LOSS=$',E10.4)
      WRITE(6,507)MVAB
 507  FORMAT(/,' PER UNIT POWER BASE=',I3,' MW')
      DO 5 J=1,NYEAR
      READ,(P(I),I=1,NODE)
      WRITE(6,520)
 520  FORMAT(///,'-------------------------------------------------------
     *--------------------')
      WRITE(6,521)J
 521  FORMAT(/,' YEAR',I2)
      WRITE(6,522)
 522  FORMAT(/,'          NET INJECTED REAL POWER  MW')
      WRITE(6,601)(P(I),I=1,NODE)
601   FORMAT(5(1X,F13.5))
      ITER=0.
39     CALL XOUT(IOUTER)
```

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```
      ITER=ITER+1
      WRITE(6,523)ITER
 523  FORMAT(////,20X,'ITERATION',I2,//)
      DO 7 I=1,NBRA
      IF(PSTAR(I).GT.PHMIN(I))GO TO 8
7     CONTINUE
      WRITE(6,40)J,ITER
 40   FORMAT(/,20X,'NO OVERLOADS IN YEAR',I3,'   ITERATION',I3,/)
      WRITE(6,520)
      GO TO 260
8     IF(ITER.GT.LIMIT)GO TO 30
      CALL JACOB
      CALL COCAL
      CALL XSOL(J)
      GO TO 39
260   IF(J.GE.NSUB)CALL REMOVE(IOUTER)
5     CONTINUE
      GO TO 6
30    WRITE(6,910)J
910   FORMAT(5X,'ITERATION LIMIT EXCEEDED DURING',I3,' TH YEAR',/)
      GO TO 6
6     CONTINUE
      STOP
      END




      SUBROUTINE XOUT(IOUTER)
      PARAMETER ND=25,NB=58
      COMMON NODE,NBRA,ETA,P(ND),PF(ND),GAMAB(NB),B(NB,NB),PSI(NB),
     *PSTAR(NB),PHMIN(NB),GMAX(NB),COST(NB),A(NB,ND),GI(ND,ND),ITEMP(NB)
     *,ITER,TYPE(NB,4),EN(NB),CA(NB),MVAB
      COMMON AMU(NB),AD1(NB),IAD(NB)
      COMMON GARB(NB)
      JFL=3
      CALL JACOB
C     THE HIGHEST CAPACITY LINE IS REMOVED FOR THE OUTAGE TEST
      IF(IOUTER.LE.3)GO TO 40
      JFL=IOUTER
40    CONTINUE
      KTERM=0
      WRITE(6,700)
700   FORMAT(70X,'OUTAGE IN BRANCH    OVERLOAD IN BRANCH',/,69X,40('*'))
      DO 510 I=1,NBRA
      ITEMP(I)=0
      GARB(I)=0.
 510  PSTAR(I)=0.
      CALL XFLOW
      DO 2 I=1,NBRA
      VAR=0.
      DO 1 JJ=1,NBRA
      VAR=VAR+(ABS(B(JJ,I))*1E+6)*(PSI(JJ)*PSI(JJ)/PHMIN(JJ)*PHMIN(JJ))
 1    CONTINUE
      VAR=VAR*GMAX(I),NBRA
      GARB(I)=VAR
  2   CONTINUE
C      GARB(I) NOW SHOWS THE RELATIVE EFFECT OF BRANCH I ON THE REST
C      OF THE SYSTEM
C      THE FOLLOWING STEPS CHOOSE THE BRANCH WITH THE LARGEST EFFECT,
C      OUT IT, AND CALCULATE THE LOADFLOW.  IN CASE OF OVERLOADS
C      REPEAT FO THE NEXT MOST EFFECTIVE BRANCH
 20   VAR=1E-8
      IX=0
      KFLAG=0
      DO 3 I=1,NBRA
      IF(GARB(I).LT.VAR.OR.ITEMP(I).EQ.1)GO TO 3
      VAR=GARB(I)
      IX=I
      KFLAG=1
  3   CONTINUE
C      HERE TEST IS MADE TO SEE IF ALL BRANCH OUTAGES HAVE CAUSED
C      OVERLOADS.
      IF(KFLAG.EQ.0)GO TO 5
      ITEMP(IX)=1
C      THIS STATMENT REPLACES THE OLD DO 500 STATMENT
      IF(GMAX(IX).LT.1E-6)GO TO 20
      IFLAG=0
      WRITE(6,701)IX
701   FORMAT(76X,I3)
      GAMAB(IX)=GAMAB(IX)-GMAX(IX)
      IF(GAMAB(IX).LT.1E-6)IFLAG=1
      CALL XFLOW
      DO 511 J=1,NBRA
      IF(J.EQ.IX.AND.IFLAG.EQ.1)GO TO 511
      IF(ABS(PSI(J)).GT.PSTAR(J))PSTAR(J)=ABS(PSI(J))
 511  CONTINUE
      GAMAB(IX)=GAMAB(IX)+GMAX(IX)
      DO 4 I=1,NBRA
      IF(I.EQ.IX.AND.IFLAG.EQ.1)GO TO 4
      IF(ABS(PSI(I)).GT.PHMIN(I))GO TO 32
      GO TO 4
32    KTERM=0
      K2=I
      DO 42 K3=K2,NBRA
      IF(K3.EQ.IX.AND.IFLAG.EQ.1)GO TO 42
      IF(ABS(PSI(K3)).LT.PHMIN(K3))GO TO 42
      WRITE(6,702)K3
702   FORMAT(98X,I3)
42    CONTINUE
      GO TO 20
4     CONTINUE
      KTERM=KTERM+1
      IF(KTERM.LT.JFL)GO TO 20
 5    RETURN
      END
```

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```
      SUBROUTINE XFLOW
      PARAMETER ND=25,NB=58
      COMMON NODE,NBRA,ETA,P(ND),PF(ND),GAMAB(NB),B(NB,NB),PSI(NB),
     *PSTAR(NB),PHMIN(NB),GMAX(NB),COST(NB),A(NB,ND),GI(ND,ND),ITEMP(NB)
     *,ITER,TYPE(NB,4),EN(NB),CA(NB),MVAB
      COMMON AMU(NB),AD1(NB),IAD(NB)
      COMMON GARB(NB)
C     THIS SUBROUTINE IS FOR DC LOADFLOW CALCULATIONS
C     JUNE 22
      DO 101 I=1,NODE
      PF(I)=P(I)/FLOAT(MVAB)
101   CONTINUE
      DO 105 I=1,NODE
      DO 106 J=1,NODE
      E=0.
      DO 107 K=1,NBRA
      E=(A(K,I)*GAMAB(K))*A(K,J)+E
107   CONTINUE
      GI(I,J)=E
106   CONTINUE
105   CONTINUE
      DO 108 I=1,NODE
      IF(GI(I,I).LT.1E-8)GO TO 109
      GO TO 108
 109  WRITE(6,110)I
 110  FORMAT(/,'*******NODE',I3,' IS ISOLATED',/)
      STOP
 108  CONTINUE
      CALL JATINV(GI,NODE,PF,1,DETERM,ND)
      DO 151 I=1,NBRA
      S=0.
      DO 152 K=1,NODE
      S=A(I,K)*PF(K)+S
152   CONTINUE
      PSI(I)=S
151   CONTINUE
      RETURN
      END
```

```
      SUBROUTINE XSOL(J)
C     THIS SUBROUTINE REPLACES THE LINEAR PROGRAM TO FIND A SET OF
C     MINIMUM COST CAPACITY ADDITIONS
      PARAMETER ND=25,NB=58
      COMMON NODE,NBRA,ETA,P(ND),PF(ND),GAMAB(NB),B(NB,NB),PSI(NB),
     *PSTAR(NB),PHMIN(NB),GMAX(NB),COST(NB),A(NB,ND),GI(ND,ND),ITEMP(NB)
     *,ITER,TYPE(NB,4),EN(NB),CA(NB),MVAB
      COMMON AMU(NB),AD1(NB),IAD(NB)
      COMMON GARB(NB)
      DO 1 K=1,NBRA
      ITEMP(K)=0
      DIF=PSTAR(K)-PHMIN(K)
      IF(DIF.GT.0.)GO TO 2
      GO TO 1
 2    ITEMP(K)=1
      CALL ILO(K,NSND,NRCVD)
      WRITE(6,92)K,NSND,NRCVD
   92 FORMAT(20X,'OVERLOAD IN BRANCH',I3,' BETWEEN BUSES',I3,' AND',I3)
    1 CONTINUE
C     ITEMP SHOWS THE OVERLOADED BRANCHES BY ASSIGNING A 1 TO THE CORRES
C     PONDING ELEMENTS
      DO 3 I=1,NBRA
      IF(ITEMP(I).EQ.1)GO TO 4
      GO TO 3
    4 VAR=0.
      DO 5 JJ=1,NBRA
      IF(JJ.EQ.I)GO TO 13
      IF(B(I,JJ).GT.0.)GO TO 5
   13 CONTINUE
      ARATIO=((B(I,JJ)*1E-6)**2)/((COST(JJ)*1E-4)*(PSTAR(I)-PHMIN(I)))
      IF(ARATIO.GT.VAR) GO TO 6
      GO TO 5
    6 VAR=ARATIO
      ITEMP(I)=JJ
    5 CONTINUE
C     ITEMP(I) NOW SHOWS THE BRANCHES TO BE VARIED, ITEMP, FOR OVERLOADS
C     IN THE I TH BRANCH
    3 CONTINUE
      IDIV=0
      DO 20 I=1,NBRA
      IF(ITEMP(I).GT.0) IDIV=IDIV+1
   20 CONTINUE
      VAR=0.
      DO 7 I=1,NBRA
      IF(ITEMP(I).GT.0) GO TO 8
      GO TO 7
    8 IVAL=ITEMP(I)
      Q=0.
      DO 9 II=1,NBRA
      IF(ITEMP(II).GT.0)Q=Q+ABS(B(II,IVAL))
    9 CONTINUE
      FACTOR=Q/IDIV
      IF(FACTOR.GT.VAR) GO TO 11
      GO TO 7
   11 VAR=FACTOR
      IBRA=IVAL
      IX=I
C     IX IS THE OVERLOADED BRANCH, IBRA IS THE BRANCH TO BE CHANGED
    7 CONTINUE
      DELTA=(PSTAR(IX)-PHMIN(IX))/ABS(B(IX,IBRA))
      CALL ILO(IBRA,NSND,NRCVD)
      WRITE(6,80)DELTA,IBRA,NSND,NRCVD
   80 FORMAT(20X,'MIN',E10.4,' P.U. MW IN BRANCH',I3,' BETWEEN BUSES',/,
     *20X,I3,' AND',I3)
      CALL ADDER(DELTA,IBRA)
      RETURN
      END
      SUBROUTINE JACOB
C     THIS SUBROUTINE CALCULATES THE JACOBIAN  ** JUNE 22**
      PARAMETER ND=25,NB=58
      COMMON NODE,NBRA,ETA,P(ND),PF(ND),GAMAB(NB),B(NB,NB),PSI(NB),
     *PSTAR(NB),PHMIN(NB),GMAX(NB),COST(NB),A(NB,ND),GI(ND,ND),ITEMP(NB)
     *,ITER,TYPE(NB,4),EN(NB),CA(NB),MVAB
      COMMON AMU(NB),AD1(NB),IAD(NB)
      COMMON GARB(NB)
      DO 105 I=1,NODE
      DO 106 J=1,NODE
      E=0.
      DO 107 K=1,NBRA
      E=(A(K,I)*GAMAB(K))*A(K,J)+E
107   CONTINUE
      GI(I,J)=E
106   CONTINUE
105   CONTINUE
      CALL JATINV(GI,NODE,C,0,DETERM,ND)
C     GI IS THE INVERSE OF GI WHICH IS AT*GAMAB*A
      DO 420 I=1,NODE
      DO 421 J=1,NBRA
      Q=0.
      DO 422 K=1,NODE
      Q=GI(I,K)*A(J,K)+Q
C     HERE A IS A TRANSPOSE
422   CONTINUE
      B(I,J)=Q
 421  CONTINUE
 420  CONTINUE
      DO 423 I=1,NBRA
      DO 424 J=I,NBRA
      Q=0.
      DO 425 K=1,NODE
      Q=A(I,K)*B(K,J)+Q
 425  CONTINUE
      B(J,I)=-Q
 424  CONTINUE
 423  CONTINUE
      IND=NBRA-1
      DO 431 I=1,IND
      K=I+1
      DO 430 J=K,NBRA
 430  B(I,J)=B(J,I)
 431  CONTINUE
      CALL XFLOW
      DO 426 I=1,NBRA
      DO 427 J=1,NBPA
      B(I,J)=B(I,J)*PSI(J)
427   CONTINUE
426   CONTINUE
      RETURN
      END
      SUBROUTINE REMOVE(IOUTER)
      PARAMETER ND=25,NB=58
      COMMON NODE,NBRA,ETA,P(ND),PF(ND),GAMAB(NB),B(NB,NB),PSI(NB),
     *PSTAR(NB),PHMIN(NB),GMAX(NB),COST(NB),A(NB,ND),GI(ND,ND),ITEMP(NB)
     *,ITER,TYPE(NB,4),EN(NB),CA(NB),MVAB
      COMMON AMU(NB),AD1(NB),IAD(NB)
      COMMON GABB(NB)
C     THIS IS A SUBROUTINE TO REMOVE UNNECESSARY LINES
      LOOP=0
1     CONTINUE
      IBRA=0
      SMALL=1E+8
      LOOP=LOOP+1
      DO 20 I=1,NBRA
      IF(AD1(I).LT.1E-6)GO TO 20
      AVG=0.
      DO 2 J=1,NBRA
      DELTA=PHMIN(J)-PSTAR(J)
      IF(DELTA.LT.1E-8)GO TO 50
C     HERE THE SUBROUTINE US EXITED BECAUSE THE SYSTEM IS  AT LIMIT
      AVG=AVG+((B(J,I)*1E+4)*(PSTAR(J)/PHMIN(J)))
2     CONTINUE
      AVG=AVG/NBRA
      IF(AVG.LT.SMALL)GO TO 3
      GO TO 20
3     SMALL=AVG
      IBRA=I
20    CONTINUE
C     IBRA NOW SHOWS THE BRANCH THAT CAN BE REDUCED WITH THE LEAST EFFECT
C     ON THE SYSTEM. THIS HAS BEEN OBTAINED BY FORMING THE RATIO OF THE COL.
C     OF THE JACOBIAN MATRIX TO THR DIFFERENCE BETWEEN PHASE ANGLES AND
C     ALLOWABLE PHASE ANGLES.
      IF(IBRA.EQ.0)GO TO 80
      SMALL=1.E-8
      DO 23 I=1,NBRA
       DELTA=PHMIN(I)-PSTAR(I)
      AVG=B(I,IBRA)/DELTA
      IF(AVG.GT.SMALL)GO TO 22
      GO TO 23
22    SMALL=AVG
       IX=I
23    CONTINUE
      IF(SMALL.LT.1.E-7)GO TO 81
       VALUE=1./SMALL
      WRITE(6,410)VALUE,IBRA
410   FORMAT(/,30X,' NEED TO REMOVE',F10.4,' P.U. MW CAPACITY FROM',I3)
      II=IAD(IBRA)
      SMALL=VALUE/TYPE(IBRA,II)
      IF(SMALL.LT.1.)GO TO 50
      GAMAB(IBRA)=GAMAB(IBRA)-TYPE(IBRA,II)
      AD1(IBRA)=AD1(IBRA)-TYPE(IBRA,II)
      IF(AD1(IBRA).LT.1.E-7)IAD(IBRA)=0
      WRITE(6,412)II,TYPE(IBRA,II),IBRA,LOOP
412   FORMAT(/,30X,' REMOVE ONE LINE OF TYPE',I3,' CAPACITY OF',F10.4,'
     *P.U. MW FROM BRANCH',I3,'  LOOP',I3)
39    CALL XOUT(IOUTER)
      DO 70 I=1,NBRA
      IF(PSTAR(I).GT.PHMIN(I))GO TO 62
```

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```
70    CONTINUE
      WRITE(6,414)
414   FORMAT(/,30X,'*****REMOVAL SUCCESSFUL')
      CALL JACOB
      GO TO 1
62    GAMAB(IBRA)=GAMAB(IBRA)+TYPE(IBRA,II)
      AD1(IBRA)=AD1(IBRA)+TYPE(IBRA,II)
      IF(IAD(IBRA).EQ.0)IAD(IBRA)=II
      WRITE(6,413)
413   FORMAT(/,30X,' REMOVAL NOT SUCCESSFUL*************')
      RETURN
90    WRITE(6,430)
430   FORMAT(/,30X,' NO FURTHER LINE REMOVAL')
      RETURN
81    WRITE(6,431)
431   FORMAT(/,30X,' POSSIBILITY OF DIVIDING BY ZERO F A')
      RETURN
50    WRITE(6,420)
420   FORMAT(/,30X,' SYSTEM ALREADY AT OPERATING LIMIT NO LINE REMOVED')
      RETURN
      END


      SUBROUTINE COCAL
      PARAMETER ND=25,NB=58
      COMMON NODE,NBRA,ETA,P(ND),PF(ND),GAMAB(NB),B(NB,NB),PSI(NB),
     *PSTAR(NB),PHMIN(NB),GMAX(NB),COST(NB),A(NB,ND),GI(ND,ND),ITEMP(NB)
     *,ITER,TYPE(NB,4),EN(NB),CA(NB),MVAB
      COMMON AMU(NB),AD1(NB),IAD(NB)
      COMMON GAPB(NB)
C     THIS SUBROUTINE CALCULATES THE COST  COEFFICIENTS COST(I) FOR
C     EACH BRANCH
      CALL XFLOW
      DO 101 J=1,NBRA
      ZZ=0.
      DO 103 K=1,NODE
      ZZ=(PF(K)*A(J,K))*PSI(J)+ZZ
103   CONTINUE
      COST(J)=(EN(J))*(CA(J)+(ETA*AMU(J))*((PSI(J)**2)-2*ZZ))
 101  CONTINUE
      RETURN
      END


      SUBROUTINE ILO(ILINE,NSND,NRCVD)
      PARAMETER ND=25,NB=58
      COMMON NODE,NBRA,ETA,P(ND),PF(ND),GAMAB(NB),B(NB,NB),PSI(NB),
     *PSTAR(NB),PHMIN(NB),GMAX(NB),COST(NB),A(NB,ND),GI(ND,ND),ITEMP(NB)
     *,ITER,TYPE(NB,4),EN(NB),CA(NB),MVAB
      COMMON AMU(NB),AD1(NB),IAD(NB)
      COMMON GAPB(NB)
      NSND=0
      NRCVD=0
      DO 30 JO=1,NODE
      IF(A(ILINE,JO).EQ.0.)GO TO 30
      IF(A(ILINE,JO).EQ.1.)NSND=JO
      IF(A(ILINE,JO).EQ.-1.)NRCVD=JO
   30 CONTINUE
      RETURN
      END




      SUBROUTINE ADDER(DELTA,IBRA)
      PARAMETER ND=25,NB=58
      COMMON NODE,NBRA,ETA,P(ND),PF(ND),GAMAB(NB),B(NB,NB),PSI(NB),
     *PSTAR(NB),PEMIN(NB),GMAX(NB),COST(NB),A(NB,ND),GI(ND,ND),ITEMP(NB)
     *,ITER,TYPE(NB,4),EN(NB),CA(NB),MVAB
      COMMON AMU(NB),AD1(NB),IAD(NB)
      COMMON GARB(NB)
      IPOS=0
      SMALL=10E+8
      DO 400 M=1,4
      IF(TYPE(IBRA,M).EQ.0.)GO TO 401
      QUOT=TYPE(IBRA,M)-DELTA
      IF(QUOT.LT.0.)GO TO 400
      IPOS=1
      IF(TYPE(IBRA,M).LT.SMALL)GO TO 402
      GO TO 400
  402 SMALL=TYPE(IBRA,M)
      MX=M
  400 CONTINUE
  401 CONTINUE
      IF(IPOS.EQ.0)GO TO 403
      GAMAB(IBRA)=GAMAB(IBRA)+TYPE(IBRA,MX)
      AD1(IBRA)=AD1(IBRA)+TYPE(IBRA,MX)
      IF(IAD(IBRA).EQ.0)IAD(IBRA)=MX
      II=IAD(IBRA)
      IF(TYPE(IBRA,MX).LT.TYPE(IBRA,II))IAD(IBRA)=MX
      WRITE(6,490)MX,IBRA,TYPE(IBRA,MX)
  490 FORMAT(/,18X,'**ADD 1 LINE OF TYPE',I3,' IN BRANCH',I3,/,
     *20X,'CAPACITY =',F10.4,' P.U. MW')
      RETURN
  403 BIG=-10E+8
      MX=0
      DO 404 M=1,4
      IF(TYPE(IBRA,M).LT.BIG)GO TO 404
      BIG=TYPE(IBRA,M)
      MX=M
  404 CONTINUE
C     NEXT STATMENTS CALCULATE THE NUMBER OF LINES TO BE ADDED
      VAT=DELTA/TYPE(IBRA,MX)
      I=VAT
      I=I+1
      VALUE=I*TYPE(IBRA,MX)
      GAMAB(IBRA)=GAMAB(IBRA)+VALUE
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```
      AD1(IBRA)=AD1(IBRA)+VALUE
      IF(IAD(IBRA).EQ.0) IAD(IBRA)=MX
      II=IAD(IBRA)
      IF(TYPE(IBRA,MX).LT.TYPE(IBRA,II)) IAD(IBRA)=MX
      WRITE(6,491) I,MX,IBRA,TYPE(IBRA,MX)
491   FORMAT(/,13X,'**ADD',I4,' LINES OF TYPE',I3,' IN BRANCH',I3,/,
     *' CAPACITY =',F10.4,' P.U. MW')
      RETURN
      END




      SUBROUTINE JATINV(A,NVAR,B,NBX,DET,NDIMA)
      PARAMETER ND=25
      DIMENSION A(NDIMA,1), B(NDIMA,1)
      DIMENSION T(ND),ISWAP(ND)
      ONE = 1.D0
      ERRFLG = 0.
      DET = 0.
      IF(NVAR.NE.0)  GO TO 18
      PRINT 861
      ERRFLG = 1.0
 861  FORMAT('0****** ERROR IN JATINV ******  N .EQ. 0',/)
18    IF(NVAR.LT.0 .OR. NBX.GE.0)  GO TO 17
      PRINT 862
      ERRFLG = 1.0
 862  FORMAT('0****** ERROR IN JATINV ****** N .GT. 0 AND K .LT. 0',/)
17    IF(NDIMA .GE. IABS(NVAR))  GO TO 13
      PRINT 863
      ERRFLG = 1.0
 863  FORMAT('0****** ERROR IN JATINV  N .GT. MA',/)
13    IF(ERRFLG .NE. 0) RETURN
      DET = 1.0
      N = IABS(NVAR)
      IF(NBX.LT.0)  GO TO 41
      NUMSWP = 0
      DO 1 I1 = 1, N
1     ISWAP(I1) = I1
      DO 2 J = 1, N
      BIG = 0
      ISAVE = 0
      DO 20 I2 = J, N
      INDEX = ISWAP(I2)
      TEMP = ABS(A(INDEX, J))
      IF(BIG.GE.TEMP)  GO TO 20
      BIG = TEMP
      ISAVE = I2
20    CONTINUE
      IF(ISAVE .EQ. 0) GO TO 86
      ISWPED = ISWAP(ISAVE)
      ISWAP(ISAVE) = ISWAP(J)
      ISWAP(J) = ISWPED
      IF (ISAVE .EQ.J) GO TO 25
      NUMSWP = NUMSWP + 1
 26     CONTINUE
        A(ISWPED, J) = ONE / A(ISWPED, J)
        IF(J.EQ.N)  GO TO 25
        DO 21 I3=  1, N
 21     T(I3) = A(I3, J+1)
        DO 22 I4 = 1, J
        I4SAVE = ISWAP(I4)
        IF(T(I4SAVE) .EQ. 0.) GO TO 22
        PIVOT = -A(I4SAVE, I4) * T(I4SAVE)
        DO 23 K1 = 1, N
 23     T(K1) = T(K1) + PIVOT*A(K1, I4)
        T(I4SAVE) = -PIVOT
  22    CONTINUE
        DO 24 I5 = 1, N
 24     A(I5, J+1) = T(I5)
  2     CONTINUE
 25     CONTINUE
        IF(NBX.EQ.0)  GO TO 5
 41     CONTINUE
        NB = IABS(NBX)
 3      DO 30 I=1,NB
        DO 31 J1 = 1, N
 31     T(J1) = B(J1, I)
        DO 32 J2 = 1, N
        J2SAVE = ISWAP(J2)
        IF(T(J2SAVE) .EQ. 0.) GO TO 32
        PIVOT = -A(J2SAVE,J2) * T(J2SAVE)
        DO 33 K2 = 1, N
 33     T(K2) = T(K2) + PIVOT*A(K2, J2)
        T(J2SAVE) = -PIVOT
 32     CONTINUE
        IF(NUMSWP .NE. 0) GO TO 35
        DO 34 J3 = 1, N
 34     B(J3, I) = T(J3)
        GO TO 30
 35     DO 36 J4 = 1, N
        J4SAVE = ISWAP(J4)
 36     B(J4, I) = T(J4SAVE)
 30     CONTINUE
 5      IF(NVAR.LT.0)  RETURN
        DO 6 J5 = 1, N
        DO 61 I6 = 1, N
 61     T(I6) = 0.
        J5SAVE = ISWAP(J5)
        T(J5SAVE) = 1.D0
        DO 62 I7 = J5, N
        I7SAVE = ISWAP(I7)
        IF(T(I7SAVE) .EQ. 0.) GO TO 62
        PIVOT = -A(I7SAVE,I7) * T(I7SAVE)
        DO 63 K3 = 1, N
 63     T(K3) = T(K3) + PIVOT*A(K3, I7)
        T(I7SAVE) = -PIVOT
 62     CONTINUE
        DO 64 I8 = 1, N
 64     A(I8, J5) = T(I8)
  6     CONTINUE
        DO 14 ICOL=1,N
```

```
99   IF(NUMSWP .EQ. 0) GO TO 100
     NDEX = ISWAP(ICOL)
     IF(NDEX.EQ.ICOL)  GO TO 14
     IROW = ISWAP(NDEX)
     DO 16 K4 = 1, N
     SWPROW = A(NDEX, K4)
     A(NDEX, K4) = A(IROW, K4)
16   A(IROW, K4) = SWPROW
     DO 12 K5 = 1, N
     SWPCOL = A(K5, ICOL)
     A(K5, ICOL) = A(K5, NDEX)
12   A(K5, NDEX) = SWPCOL
     NUMSWP = NUMSWP - 1
     ISWAP(NDEX) = NDEX
     ISWAP(ICOL) = IROW
     GO TO 99
14   CONTINUE
100  RETURN
86   PRINT 860, J
     DET = 0
 860 FORMAT('****** ERROR IN JATINV ****** PIVOT COLUMN',I4,' IS ZERO')
     RETURN
     END
```

APPENDIX G

LISTING OF THE PLANNING PROGRAM FOR THE AC MODEL

This Appendix describes the format of the input data and lists the program (Figure G-1) for the fast-decoupled AC power-flow model, in which the line-removing subroutine is not incorporated.

INPUT DATA

The input data for this program includes:

(1) General information card: LIMIT, IDEB, NODE, NYEAR, ETA, MVAB, NSUB, VUP, VLO, IOUTER, where LIMIT = maximum number of iterations allowed, IDEB = debugging printout, NODE = number of nodes in the system, NYEAR = number of planning periods, ETA = yearly cost (in dollars) of one per-unit power loss, MVAB = base power in MW, NSUB = not used, VUP = maximum allowable bus-voltage magnitude in per unit, VLO = minimum allowable bus voltage magnitude in p.u., and IOUTER = stopping criterion for the automatic contingency selection subroutine (default value is 3);

(2) Bus data: NBUS, TY, V1, V2, B, QUP, QLO, followed by a zero card (0 0 0. 0. 0. 0. 0.), where NBUS = bus number, TY = bus type (0 = Load bus, 3 = Slack bus, 4 = Generator bus), V1 = (a) real power output of the bus in p.u. for load buses, (b) voltage magnitude in p.u. for slack buses, or (c) real power into the bus in p.u. for generator buses, V2 = (a) reactive power out of the bus in p.u. for load buses, (b) voltage phase angle in degrees for slack buses, or (c) voltage magnitude in p.u. for generator buses, B = susceptance to ground in p.u., QUP = generator maximum reactive power limit, and QLO = generator minimum reactive power limit; and

(3) Branch cards: NS, NR, K, R, X, YS, POMAX, ENCO, CAPCO, where NS and NR = buses to which branch is connected (for TAP transformers, NS is the tap side), K = branch type (1 = transmission line and 2 = transformer), R = series PI resistance in p.u. for lines or series resistance (nominal side) for transformers, X = series PI reactance in p.u. for lines or series reactance in p.u. (nominal side) for transformers, YS = shunt PI susceptance in p.u. for lines or tap position for transformers, POMAX = flow rating of the

element in MVA, ENCO = yearly environmental cost (in dollars) of adding one p.u. of capacity on the branch, and CAPCO = yearly capital cost (in dollars, fixed charges) of adding one per unit of capacity on the branch; and

(4) Future bus data cards: NBUS, TY, V1, V2, B, QUP, QLO, followed by a zero card (0 0 0. 0. 0. 0. 0.) for every planning period.

```
C       THIS PROGRAM IS THE VERSION OF THE PLANNING PROGRAM USING
C     FAST DECOUPLED LOAD FLOW
C     INPUT DATA ARE
C                  GENERAL INFO CARD
C                  LIMIT, IDEB, NODE, NYEAR, ETA, MVAB, NSUB, VUP, VLO,IOUTER
C       WHERE
C                  LIMIT  IS THE MAX NUMBER OF ITERATIONS FOR PLANNING
C                  IDEB  IS THE VARIABLE USED TO PRINT OUT THE INPUT DATA
C                        0   NO INPUT DATA OR INTERMEDIATE VARIABLES
CC                       1  INPUT DATA
C                        2  INPUT DATA AND XP,XQ
C                        4  INPUT DATA,AND XP,XQ,B',B'',DD,DV,INP,INQ
C                        6  INPUT DATA,AND XP,XQ,B',B''.DD.DV,INP,INQ,YBUS
C                            XP AND XQ ARE THE REAL AND REACTIVE POWER
C                            MISMATCHES
C                            B' AND B'' ARE THE MATRICES IN THE FAST -D
C                            LOAD FLOW
C                            DD AND DV ARE THE VOLTAGE PHASE ANGLE AND
C                            MAGNITUDE CORRECTIONS
C                            INP AND INQ ARE THE RENUMBERING PIVOTS
C                            YBUS IS THE BUS ADMITTANCE MATRIX
C                  NYEAR  IS THE NUMBER OF YEARS IN THE PLANNING STUDY
C                  ETA IS THE COST OF ONE UNIT OF ENERGY LOSS IN ONE YEAR
C                  MVAB  IS THE BASE MEGAWATTS
C                  NSUB   IS THE NUMBER OF YEARS AFTER WHICH WE CAN REMOVE LINES
C                  VUP IS THE MAXIMUM ALLOWABLE OVER VOLTAGE IN P.U.
C                  VLO IS THE MAXIMUM ALLOWABLE UNDER VOLTAGE IN P.U.
C                  IOUTER  IS THE STOPPING CRITERION FOR OUTAGE TESTS
C
C       BUS DATA CARDS(NODE OF THEM) FOLLOWED BY A ZERO CARD
C            NBUS,TY,V1,V2,B,QUP,QLO
C       WHERE
C                  NBUS  IS THE BUS NUMBER
C                  TY   IS THE BUS TYPE
C                            0   LOAD BUS
C                               V1=P OUT OF THE BUS IN P.U.
C                               V2=Q OUT OF THE BUS IN P.U.
C                            3  SLACK BUS
C                               V1=BUS VOTAGE MAGNITUDE IN P.U.
C                              V2  VOLT PHASE ANGLE(DGREES)
C                            4  GEN BUS
C                               V1=P INTO THE BUS IN P.U.
C                               V2=BUS VOLTAGE MAGNITUDE IN P.U.
C                  B  IS THE SUSCEPTANCE TO GROUND IN P.U.
C                  QUP IS THE GEN. QMAX IN MVARS
C                  QLO IS THE GEN. QMIN IN MVARS
C
C       BRANCH CARDS FOLLOWED BY A ZERO CARD
C            NS,NR,K,S,YS,POMAX,ENCO,CAPCO
C       WHERE
C                            NS  IS THE ORIGIN NODE
C                            NR  IS THE TERMINAL NODE
C                            K  IS
C                              1  IF TRANSMISSION LINE
C                              2  IF TRANSFORMER
C                            S   IS THE SERIES IMPEDANCE  R   X IN P.U.
C                            YS  IS THE SHUNT SUSCEPTANCE IN P.U.
C                                 OR  THE TRANSFORMER TAP POSITION
C                  POMAX IS THE POWER RATING OF LINE IN MVA
```

Figure G-1. Listing of planning program using fast decoupled load flow.

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```
C                                 ENCO= ENVIRONMENTAL COST P.U. CAPACITY
C                                 CAPCO= CAPITAL COST OF THE LINE P.U.CAPACITY
C                                             (YEARLY INSTALLMENTS)
C        FUTURE  BUS DATA CARDS NYEAR-1 SET OF THEM EACH SET FOLLOWED BY ZERO
C                    NBUS,TY,V1,V2,B,QUP,QLO
        IMPLICIT INTEGER(A-Z)
      REAL DRAD,TOL,ETA,MVAB,V1,V2,B,SP1,SP2,RTOX,PCMAX,ENCO,CAPCO,YS,
     1ALF,PHMAX,PHMIN,STYPE,EN,CA,A,AMU,BC,DEL,BP,BPP,SUM
      REAL GMAX,PSTAR,COST,AD1,VUP,VLO,QUP,QLO,Q1,Q2
      COMPLEX YBUS,S1,S2,S,TYPE
      PARAMETER ND=30,NB=66
      COMMON/BTYPE/BTYPE(ND)
      COMMON/YBUS/YBUS(ND,ND)
      COMMON/SP1/SP1(ND)
      COMMON/SP2/SP2(ND)
      COMMON/PHMIN/PHMIN(NB)
      COMMON/TYPE/TYPE(NB,4)
      COMMON/STYPE/STYPE(NB,5)
      COMMON/EN/EN(NB)
      COMMON/CA/CA(NB)
      COMMON/COST/COST(NB)
      COMMON/A/A(NB,ND)
      COMMON/AMU/AMU(NB)
      COMMON/BC/BC(ND)
      COMMON/DEL/DEL(ND)
      COMMON/BP/BP(ND,ND)
      COMMON/BPP/BPP(ND,ND)
      COMMON/GMAX/GMAX(NB)
      COMMON/PSTAR/PSTAR(NB)
      COMMON/AD1/AD1(NB)
      COMMON/IAD/IAD(NB)
      COMMON/QUP/QUP(ND)
      COMMON/QLO/QLO(ND)
      COMMON/VIND/VIND(ND)
      COMMON/SCLR3/VUP,VLO
      COMMON KPOINT
      COMMON/SCLR/NODE,NBRA,TOL,DRAD,LIMIT,NYEAR,MVAB,NSUB,IDEB
      COMMON/SCLR2/CP,CQ
      COMMON/ETA/ETA
      COMMON/IOUTER/IOUTER
       KPOINT=0
      DRAD=57.29578
      TOL=.0001
C     INITIALIZING THE ARRAYS
      DO 406 I=1,NB
      STYPE(I,5)=0.
      EN(I)=0.
      CA(I)=0.
      AD1(I)=0.
      IAD(I)=0
      GMAX(I)=0.
      COST(I)=0.
      PHMIN(I)=1E+6
      AMU(I)=0.
      DO 407 J=1,4
      TYPE(I,J)=0.
      STYPE(I,J)=0.
407   CONTINUE
406   CONTINUE
```

```
      DO 102 I=1,ND
      BTYPE(I)=0
      VIND(I)=0
      SP1(I)=0.
      SP2(I)=0.
102   CONTINUE
      DO 103 I=1,ND
      DO 103 J=1,ND
103   YBUS(I,J)=0.
      DO 408 I=1,NB
      DO 408 J=1,ND
408   A(I,J)=0.
340    FORMAT(' GENERAL DATA',//,1X,'LIMIT  IDEB   NODE    YEARS       E
     1TA     MVA-BASE     NSUB        V-MAX          V-MIN    IOUTER')
       READ,LIMIT,IDEB,NODE,NYEAR,ETA,MVAB,NSUB,VUP,VLO,IOUTER
       IF(IDEB.GT.0)WRITE(-,340)
       IF(IDEB.GT.0)WRITE(-,343)LIMIT,IDEB,NODE,NYEAR,ETA,MVAB,NSUB,VUP,V
     1LO,IOUTER
343    FORMAT(1X,I4,2X,I4,3X,I4,4X,I4,4X,F9.5,4X,F9.5,4X,I4,4X,F9.5,4X,F9
     1.5,6X,I3)
C      BUS DATA
       IF(IDEB.GT.0)WRITE(-,341)
341    FORMAT(///,30X,'*BUS DATA',/,' BUS TY',7X,'V1',10X,'V2',11X,'B',10
     1X,'Q-MAX',7X,'Q-MIN')
30     CONTINUE
       READ,NBUS,TY,V1,V2,B,Q1,Q2
       IF(IDEB.GT.0)WRITE(6,91)NBUS,TY,V1,V2,B,Q1,Q2
91     FORMAT(1X,I4,I3,5F12.5)
       IF(NBUS.EQ.0)GO TO 31
       IF(NBUS.GT.NODE)GO TO 52
       QUP(NBUS)=Q1/MVAB
       QLO(NBUS)=Q2/MVAB
C      QUP AND QLO ARE NOW IN P.U.MVARS
       S1=CMPLX(0.,B)
       YBUS(NBUS,NBUS)=YBUS(NBUS,NBUS)+S1
       BTYPE(NBUS)=TY
       IF(TY.EQ.0)GO TO 59
       SP1(NBUS)=V1
       SP2(NBUS)=V2
       IF(TY.EQ.3)SP2(NBUS)=SP2(NBUS)/DRAD
       GO TO 58
59     SP1(NBUS)=-V1
       SP2(NBUS)=-V2
58     CONTINUE
       GO TO 30
31     CONTINUE
C      SIMULATION OF THE NETWORK
       NSIND=9000
       NRIND=NSIND
       ICOUNT=0
       I=0
       RTOX=0.
C      BRANCH CARDS
       IF(IDEB.GT.0)WRITE(-,342)
342    FORMAT(//,30X,'*LINE DATA',/,1X,'  NS   NR K',6X,'R',11X,'X',10X,'Y
     1S',7X,'PCMAX      ENCO          CAPCO        BRANCH')
109    READ,NS,NR,K,S,YS,PCMAX,ENCO,CAPCO
       IF(NS.EQ.0.AND.NR.EQ.0)GO TO 4
```

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```
231    IF(NS.NE.NSIND.OR.NR.NE.NRIND)GO TO 200
       IF(ENCO.LT.0.)GO TO 201
       ICOUNT=ICOUNT+1
201    CONTINUE
       IF(IDEB.GT.0)WRITE(6,92)NS,NR,K,S,YS,POMAX,ENCO,CAPCO,I
92     FORMAT(1X,2I4,I2,6F12.5,8X,I3)
C      FORMATION OF THE YBUS
       S1=CMPLX(0.,YS)
       S2=S1
       IF(K.EQ.1)GO TO 68
       YS=1./YS
       S1=(1.-YS)/S
       S2=(YS-1.)*YS/S
       S=S/YS
68     S=1./S
       YBUS(NS,NR)=YBUS(NS,NR)-S
       YBUS(NR,NS)=YBUS(NR,NS)-S
       YBUS(NS,NS)=YBUS(NS,NS)+S
       YBUS(NR,NR)=YBUS(NR,NR)+S
       YBUS(NS,NS)=YBUS(NS,NS)+S1
       YBUS(NR,NR)=YBUS(NR,NR)+S2
       POMAX=POMAX/MVAB
       S=1./S
       IF(ENCO.LT.0.)GO TO 233
       RTOX=RTOX+REAL(S)/AIMAG(S)
233    CONTINUE
C      CHECK FOR ARTIFICIAL LINES
       IF(POMAX.LT.1E-5)GO TO 232
       ALF=AIMAG(S)/(AIMAG(S)**2+REAL(S)**2)
       ALF=ABS(ALF)
       PHMAX=POMAX/ALF
       IF(PHMAX.LT.PHMIN(I))PHMIN(I)=PHMAX
232    CONTINUE
       IF(ENCO.LT.0.)GO TO 234
       IF(ALF.GT.GMAX(I))GMAX(I)=1./AIMAG(S)
234    CONTINUE
C      GMAX SHOWS 1/AIMAG(S)   'APPROXIMATION'
C      STATMENTS 96,97, AND 98 OF AABB WITH MODIFIED OUTAGE TESTS HAVE BEEN
C      ELIMINATED. THESES STATMENTS BUILT GMAX ARRAY. USE WILL BE MADE
C      OF TYPE AND STYPE ARRAYS INSTEAD.
C      THE FOLLOWING STATMENTS ARE NEEDED TO CONSTRUCT THE TYPE ARRAY
C      STYPE(I,5) SHOWS THE SUM OF ALL SHUNT REACTANCES IN BRANCH I
       STYPE(I,5)=STYPE(I,5)+(AIMAG(S1)+AIMAG(S2))/2.
420    DO 410 L=1,4
       IF(AIMAG(TYPE(I,L)).LT.1E-6)GO TO 240
       IF(ENCO.LT.0.)GO TO 109
       IF(ABS(1.-CABS((S)/TYPE(I,L))).LT.1E-4)GO TO 241
410    CONTINUE
       WRITE(6,415)I
415    FORMAT(/,'**MORE THAN 4 LINE TYPES IN BRANCH',I4,' CHANGE STATMENT
      1420 AND THE DIMENSION STATMENT FOR TYPE AND STYP  ARRAYS',/)
       STOP
240    TYPE(I,L)=S
       STYPE(I,L)=(AIMAG(S1)+AIMAG(S2))/2.
241    CONTINUE
       GO TO 109
200    NSIND=NS
       NRIND=NR
       I=I+1
      IF(ENCO.LT.0.)GO TO 237
      EN(I)=ENCO
      CA(I)=CAPCO
      GO TO 238
237   EN(I)=1E+8
      CA(I)=1E+8
238   CONTINUE
C     FORMATION OF THE INCIDENCE MATRIX
      IF(NS.EQ.0)GO TO 1
      A(I,NS)=1.
1     CONTINUE
      IF(NR.EQ.0)GO TO 2
      A(I,NR)=-1.
2     CONTINUE
      IF(I.EQ.1)GO TO 220
      KI=I-1
      AMU(KI)=RTOX/FLOAT(ICOUNT)
      RTOX=0.
      ICOUNT=1
      GO TO 201
220   ICOUNT=1
      GO TO 201
4     CONTINUE
      AMU(I)=RTOX/FLOAT(ICOUNT)
      RTOX=0.
      NBRA=I
      IF(IDEB.GT.5)WRITE(6,400)((YBUS(I,J),J=1,NODE),I=1,NODE)
400   FORMAT(1X,'YBUS',10F12.5)
      DO 720 I=1,NODE
      EC(I)=1.
720   DEL(I)=0.
      DO 721 I=1,NODE
      IF(BTYPE(I).EQ.0)GO TO 721
      IF(BTYPE(I).EQ.3)GO TO 750
      EC(I)=SP2(I)
      GO TO 721
750   EC(I)=SP1(I)
721   CONTINUE
              CALL XFLOW
      WRITE(6,104)
104   FORMAT(///////,2X,'BASE CASE LOAD FLOW RESULTS',///,2X,'BUS',4X,'V
     1OLTAGE MAG.',4X,'PHASE-DEGREES')
      WRITE(6,105)
      DO 402 I=1,NODE
      YS=DEL(I)*DRAD
      WRITE(6,401)I,EC(I),YS
401   FORMAT(2X,I3,4X,F12.5,4X,F10.5)
402   CONTINUE
C
      WRITE(6,105)
105   FORMAT('--------------------------------------------')
      DO 5 J=1,NYEAR
      WRITE(6,106)
106   FORMAT('------------------------------------------------------------
     1------------------------------------------------------------')
      WRITE(6,521)J
521   FORMAT(/,'   YEAR',I2)
      WRITE(6.300)
```

```
300   FORMAT(//,9X,'THE BUS DATA FOR THIS YEAR ARE',//,11X,'BUS  I   TYP
     1E   I     VALUES IN P.U.  I     VALUES IN P.U. OR DEG.  I')
      WRITE(6,107)
107   FORMAT(10X,'-------I----------I---------------------I-------------
     1---------------I')
      DO 302 I=1,NODE
        JK=STYPE(I)
      IF(JK.EQ.0)GO TO 310
      IF(JK.EQ.3)GO TO 313
      IF(JK.EQ.4)GO TO 314
      WRITE(6,301)
301   FORMAT(' ***BUS TYPE ERROR--- STOP')
      STOP
310   V1=-SP1(I)
      V2=-SP2(I)
      WRITE(6,320)I,V1,V2
320   FORMAT(11X,I3,'  I    P,Q   I  P-OUT=',F12.5,' I  Q-OUT=',F12.5,'
     1          I')
      GO TO 302
313   V2=SP2(I)*DRAD
      V1=SP1(I)
      WRITE(6,323)I,V1,V2
323   FORMAT(11X,I3,'  I   SLACK  I  V-MAG=',F12.5,' I  PHASE=',F12.5,'
     1          I')
      GO TO 302
314   V1=SP1(I)
      V2=SP2(I)
      WRITE(6,324)I,V1,V2
324   FORMAT(11X,I3,'  I    P,V   I   P-IN=',F12.5,' I  V-MAG=',F12.5,'
     1          I')
302   CONTINUE
      WRITE(6,107)
      ITER=0.
39    CALL XOUT
      ITER=ITER+1
      WRITE(6,523)ITER
523   FORMAT(/////,20X,'ITERATION',I2,///,21X,'SYSTEM CONDITION',20X,'I'
     1,20X,'CORRECTIVE MEASURE',34X,'I',/,9X,'--------------------------
     1-------------------I--------------------------------------------
     2------------------------------I')
      DO 7 I=1,NBRA
      IF(PSTAR(I).GT.0.)GO TO 8
7     CONTINUE
      WRITE(6,40)J,ITER
40    FORMAT(10X,'NO OVERLOADS IN YEAR',I3,' ITERATION',I3,11X,'I',72X,'
     1I')
      KPOINT=1
      GO TO 260
8       IF(ITER.GT.LIMIT)GO TO 630
      KPOINT=0
      CALL JACOB
      CALL COCAL
      CALL XSOL(J)
      GO TO 39
260   CONTINUE
C     HERE CALLING XOUT WILL CALL VCOR BECAUSE KPOINT IS EQUAL TO 1
      CALL XOUT
      KPOINT=0
901   CONTINUE
```

```
      IF(J.EQ.NYEAR)GO TO 6
      IF(IDEB.GT.0)WRITE(6,341)
601   READ,NBUS,TY,V1,V2,B,Q1,Q2
      IF(IDEB.GT.0)WRITE(6,91)NBUS,TY,V1,V2,B,Q1,Q2
      IF(NBUS.EQ.0)GO TO 611
      IF(NBUS.GT.NODE)GO TO 52
      VIND(NBUS)=0
      QUP(NBUS)=Q1
      QLO(NBUS)=Q2
      BTYPE(NBUS)=TY
      S1=CMPLX(0.,B)
      YBUS(NBUS,NBUS)=YBUS(NBUS,NBUS)+S1
      IF(TY.EQ.0)GO TO 659
      SP1(NBUS)=V1
      SP2(NBUS)=V2
      IF(TY.EQ.3)SP2(NBUS)=SP2(NBUS)/DRAD
      GO TO 658
659   SP1(NBUS)=-V1
      SP2(NBUS)=-V2
658   CONTINUE
      GO TO 601
611     CONTINUE
5     CONTINUE
      GO TO 6
630   CONTINUE
910   FORMAT(5X,'ITERATION LIMIT EXCEEDED DURING',I3,' TH YEAR',/)
      KPOINT=0
      GO TO 6
6     CONTINUE
C
              STOP
52    WRITE(6,612)
612   FORMAT('****** DATA ERROR BUS NUMBER GREATER THAN MAX SPECIFIED')
      STOP
            END




      SUBROUTINE BUILD(CP,CQ)
C      THIS SUBROUTINE  BUILDS B' AND B'' MATRI ES
      IMPLICIT INTEGER(A-Z)
      REAL STYPE,A,TOL,DRAD,MVAB,BP,BPP,VEB,VEG,XINV
      COMPLEX YBUS
      PARAMETER ND=30,NB=66
      COMMON/YBUS/YBUS(ND,ND)
      COMMON/INP/INP(ND)
      COMMON/INQ/INQ(ND)
      COMMON/PINP/PINP(ND)
      COMMON/PINQ/PINQ(ND)
      COMMON/BP/BP(ND,ND)
      COMMON/BPP/BPP(ND,ND)
      COMMON/BTYPE/BTYPE(ND)
      COMMON/STYPE/STYPE(NB,5)
      COMMON/A/A(NB,ND)
      COMMON/SCLR/NODE,NBRA,TOL,DRAD,LIMIT,NYEAR,MVAB,NSUB,IDEB
       DO 1 I=1,NODE
      INP(I)=0
      INQ(I)=0
      PINP(I)=0
      PINQ(I)=0
      BP(I,I)=0.
1     CONTINUE
      CP=0
      CQ=0
      DO 10 I=1,NODE
      IF(BTYPE(I).EQ.3)GO TO 10
      CP=CP+1
      INP(CP)=I
      PINP(I)=CP
      IF(BTYPE(I).NE.0)GO TO 10
      CQ=CQ+1
      INQ(CQ)=I
      PINQ(I)=CQ
10    CONTINUE
      DO 20 I=1,NODE
      IF(BTYPE(I).EQ.3)GO TO 20
      II=PINP(I)
      DO 12 J=1,NODE
      IF(I.EQ.J)GO TO 12
      VEB=AIMAG(YBUS(I,J))
      VEG=REAL(YBUS(I,J))
      XINV=0.
      IF(ABS(VEB).GT.1E-5)XINV=VEB+VEG*VEG/VEB
      BP(II,II)=BP(II,II)+XINV
      IF(BTYPE(J).EQ.3)GO TO 12
      JJ=PINP(J)
      BP(II,JJ)=-XINV
12    CONTINUE
20    CONTINUE
      DO 22 I=1,CQ
      DO 22 J=1,CQ
      II=INQ(I)
      JJ=INQ(J)
      IF(J.GT.I)GO TO 21
      BPP(I,J)=-AIMAG(YBUS(II,JJ))
      BPP(J,I)=BPP(I,J)
21    CONTINUE
22    CONTINUE
      IF(IDEB.GT.3)WRITE(6,98)(INP(I),I=1,CP)
      IF(IDEB.GT.3)WRITE(6,99)(INQ(I),I=1,CQ)
98    FORMAT(' INP',4I4)
99    FORMAT(' INQ',4I4)
      IF(IDEB.GT.3)WRITE(6,3)((BP(I,J),J=1,CP),I=1,CP)
3     FORMAT(1X,'BP',4F12.5)
      IF(IDEB.GT.3)WRITE(6,4)((BPP(I,J),J=1,CQ),I=1,CQ)
4     FORMAT(1X,'BPP',3F12.5)
      RETURN
      END
```

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```
       SUBROUTINE MISP(CP,N)
C      THIS SUBROUTINE CALCULATES THE REAL POWER MISMATCH
      IMPLICIT INTEGER(A-Z)
      REAL TOL,DRAD,MVAB
      REAL XP
      REAL AJ,BKM,GKM,EC,THET,DEL,SP1
       REAL PI
      COMPLEX YBUS
      PARAMETER ND=30,NB=66
      COMMON/YBUS/YBUS(ND,ND)
      COMMON/EC/EC(ND)
      COMMON/SP1/SP1(ND)
      COMMON/XP/XP(NB)
      COMMON/INP/INP(ND)
      COMMON/DEL/DEL(ND)
      COMMON/SCLR/NODE,NBRA,TOL,DRAD,LIMIT,NYEAR,MVAB,NSUB,IDEB
      PI=3.1415926*2.
       DO 2 I=1,CP
       INT=INP(I)
       AJ=0.
       DO 1 J=1,N
       BKM=AIMAG(YBUS(INT,J))
       GKM=REAL(YBUS(INT,J))
       THET=DEL(INT)-DEL(J)
       THET=AMOD(THET,PI)
       GKM=GKM*COS(THET)
       BKM=BKM*SIN(THET)
1      AJ=AJ-EC(J)*(GKM+BKM)
       AJ=EC(INT)*AJ
      XP(I)=SP1(INT)-AJ
      XP(I)=XP(I)/EC(INT)
2      CONTINUE
      IF(IDEB.GT.1)WRITE(6,3)(XP(I),I=1,CP)
3     FORMAT(1X,'XP',10F12.5)
       RETURN
       END


       SUBROUTINE MISQ(CQ,N)
C      THIS SUBROUTINE CALCULATES THE REACTIVE POWER MISMATCH
      IMPLICIT INTEGER(A-Z)
      COMPLEX YBUS
      REAL TOL,DRAD,MVAB
      REAL XQ
      REAL AJ,BKM,GKM,THET,DEL,EC,SP2
      REAL PI
      PARAMETER ND=30,NB=66
      COMMON/YBUS/YBUS(ND,ND)
      COMMON/EC/EC(ND)
      COMMON/SP2/SP2(ND)
      COMMON/INQ/INQ(ND)
      COMMON/XQ/XQ(NB)
      COMMON/DEL/DEL(ND)
      COMMON/SCLR/NODE,NBRA,TOL,DRAD,LIMIT,NYEAR,MVAB,NSUB,IDEB
       PI=3.1415926*2.
        DO 2 I=1,CQ
        INT=INQ(I)
        AJ=0.
       DO 1 J=1,N
       BKM=AIMAG(YBUS(INT,J))
       GKM=REAL(YBUS(INT,J))
       THET=DEL(INT)-DEL(J)
      THET=AMOD(THET,PI)
       GKM=GKM*SIN(THET)
       BKM=BKM*COS(THET)
1      AJ=AJ+EC(J)*(GKM-BKM)
       AJ=EC(INT)*AJ
      XQ(I)=SP2(INT)-AJ
      XQ(I)=XQ(I)/EC(INT)
2      CONTINUE
      IF(IDEB.GT.1)WRITE(6,3)(XQ(I),I=1,CQ)
3     FORMAT(1X,'XQ',10F12.5)
       RETURN
      END
```

```
       SUBROUTINE XFLOW
      IMPLICIT INTEGER(A-Z)
      REAL TOL,DRAD,MVAB
      REAL BP,BPP,XP,XQ,DEL,EC,ERR
      REAL A
      REAL PI,ANG
      REAL QUP,QLO
      REAL ERP,ERQ
      REAL U,V
      REAL SP2
      COMPLEX VOL,S
      COMPLEX YBUS
      PARAMETER ND=30,NB=66
      COMMON/BTYPE/BTYPE(ND)
      COMMON/SP2/SP2(ND)
      COMMON/VOL/VOL(ND)
      COMMON/QLO/QLO(ND)
      COMMON/QUP/QUP(ND)
      COMMON/VIND/VIND(ND)
      COMMON/YBUS/YBUS(ND,ND)
      COMMON/BP/BP(ND,ND)
      COMMON/A/A(NB,ND)
      COMMON/INP/INP(ND)
      COMMON/BPP/BPP(ND,ND)
      COMMON/XP/XP(NB)
      COMMON/XQ/XQ(NB)
      COMMON/PINP/PINP(ND)
      COMMON/PINQ/PINQ(ND)
      COMMON/DEL/DEL(ND)
      COMMON/EC/EC(ND)
      COMMON/ISO/ISO
      COMMON/SCLR/NODE,NBRA,TOL,DRAD,LIMIT,NYEAR,MVAB,NSUB,IDEB
      COMMON/SCLR2/CP,CQ
C      THIS SUBROUTINE IS A LOADFLOW PROGRAM USING THE FAST DECOUPLED
C      TECHNIQUE AS DEVELOPED BY S.STOT . IT BEGINS WITH FLAT START
      ISO=0
      PI=3.1415926
      CALL BUILD(CP,CQ)
C     THE FOLLOWING STATMENTS UP TO 108 ARE TO DETECT NODE ISOLATIONS
      DO 108 I=1,CP
      IF(BP(I,I).LT.1E-8)GO TO 109
      GO TO 108
109   INT=INP(I)
      WRITE(6,110)INT
110   FORMAT(10X,'BUS',I3,' IS ISOLATED',29X,'I',72X,'I')
      ISO=1
      RETURN
108   CONTINUE
      CALL FACTOR(BP,CP,ND)
      CALL FACTOR(BPP,CQ,ND)
       J=0
       KP=1
       KQ=1
1      CALL MISP(CP,NODE)
       ERR=0.
       DO 2 I=1,CP
       IF(ABS(XP(I)).GT.ERR)ERR=ABS(XP(I))
2      CONTINUE
      ERP=ERR
       IF(ERR.LT.TOL)GO TO 5
      CALL SOLVE(BP,XP,CP,ND,NB)
      IF(IDEB.GT.3)WRITE(-,800)(XP(I),I=1,CP)
800   FORMAT(1X,'DD',10F12.5)
       DO 3 I=1,NODE
       INT=PINP(I)
       IF(INT.EQ.0)GO TO 3
       DEL(I)=DEL(I)+XP(INT)
3      CONTINUE
       KQ=1
       GO TO 6
5      KP=0
      IF(KQ.EQ.0)GO TO 14
6      CONTINUE
       CALL MISQ(CQ,NODE)
       ERR=0.
       DO 4 I=1,CQ
       IF(ABS(XQ(I)).GT.ERR)ERR=ABS(XQ(I))
4      CONTINUE
      ERQ=ERR
       IF(ERR.LT.TOL)GO TO 10
      CALL SOLVE(BPP,XQ,CQ,ND,NB)
      IF(IDEB.GT.3)WRITE(-,801)(XQ(I),I=1,CQ)
801   FORMAT(1X,'DV',10F12.5)
       DO 7 I=1,NODE
       INT=PINQ(I)
       IF(INT.EQ.0)GO TO 7
       EC(I)=EC(I)+XQ(INT)
7      CONTINUE
       KP=1
       GO TO 11
10     KQ=0
      IF(KP.EQ.0)GO TO 14
11     CONTINUE
       J=J+1
      IF(J.GT.20)GO TO 12
C     THE FOLLOWING STSTMENTS UP TO 299 ARE TO CALCULATE POWER FLOWS AND
C      TO CHECK Q LIMITS
      IF(ERP.LT.ERQ)ERP=ERQ
      IF(ERP.LT.1E-3)GO TO 1
      DO 210 II=1,NODE
      ANG=DEL(II)
      ANG=AMOD(ANG,PI)
      U=EC(II)*COS(ANG)
      V=EC(II)*SIN(ANG)
210   VOL(II)=CMPLX(U,V)
      KFLAG=0
      DO 214 II=1,NODE
      IF(BTYPE(II).NE.4)GO TO 213
220   CONTINUE
C     COMPUTE Q
      S=CMPLX(0.,0.)
      DO 211 JJ=1,NODE
211   S=S+YBUS(II,JJ)*VOL(JJ)
      S=CONJG(S)
      S=VOL(II)*S
      U=AIMAG(S)
      IF(U.LT.QUP(II).AND.U.GT.QLO(II))GO TO 214
      IF(U.LT.QUP(II))GO TO 222
C     HERE U IS  .GT.QUP
      V=SP2(II)
      SP2(II)=QUP(II)
      QUP(II)=V
      BTYPE(II)=0
      WRITE(6,230)II
 230  FORMAT(9X,'*BUS TYPE CHANGE IN BUS',I3,22X,'I',72X,'I')
      KFLAG=1
      VIND(II)=1
      GO TO 214
 222  CONTINUE
C     HERE U  IS .LT.QLO
      V=SP2(II)
      SP2(II)=QLO(II)
      QLO(II)=V
      BTYPE(II)=0
      WRITE(6,230)II
      KFLAG=1
      VIND(II)=-1
      GO TO 214
 213  IF(VIND(II).EQ.0)GO TO 214
      IF(VIND(II).EQ.1)GO TO 215
      IF(VIND(II).EQ.-1)GO TO 216
      WRITE(6,231)II
 231  FORMAT(' ERROR VIND(I) HAS VALUE OTHER THAN 0,1,-1 IN BUS',I3)
      STOP
 215  V=QUP(II)
C     HERE V IS THE OLD VOLTAGE LIMIT OF BUS II
      IF(EC(II).LT.V)GO TO 214
      QUP(II)=SP2(II)
      SP2(II)=V
      KFLAG=1
      BTYPE(II)=4
      EC(II)=V
      WRITE(6,230)II
      VIND(II)=0
      GO TO 214
216   V=QLO(II)
C     HERE V IS THE OLD BUS VOLTAGE LIMIT
      IF(EC(II).GT.V)GO TO 214
      QLO(II)=SP2(II)
      SP2(II)=V
      KFLAG=1
      BTYPE(II)=4
      EC(II)=V
      WRITE(6,230)II
      VIND(II)=0
214   CONTINUE
      IF(KFLAG.EQ.1)GO TO 218
      GO TO 1
218   CALL BUILD(CP,CQ)
      CALL FACTOR(BP,CP,ND)
      CALL FACTOR(BPP,CQ,ND)
299   CONTINUE
       GO TO 1
12     WRITE(6,13)ERR,TOL
13     FORMAT('****MAXIMUM NUMBER OF LOAD FLOW ITERATIONS EXCEEDED 20
     1MAX ERROR AND TOLERATION ARE',2F10.4)
       STOP
14    CONTINUE
C     THE FOLLOWING STATMENTS ARE TO FORM THE PSI ARRAY
      DO 151 I=1,NBRA
      ERR=0.
      DO 152 K=1,NODE
      ERR=A(I,K)*DEL(K)+ERR
152   CONTINUE
      XP(I)=ERR
C     XP HERE IS SAME AS THE OLD PSI. ERR IS THE SAME AS OLD S
151   CONTINUE
      RETURN
       END


      SUBROUTINE FACTOR(A,N,NDIMA)
C*     THIS SUBROUTINE FACTORS A SQUARE MATRIX
C      THE ARGUMENTS ARE
C                   A   THE N BY N MATRIX TO BE FACTORED
C                   N  THE DIMENSION OF THE MATRIX TO BE FACTORED
C                   NDIMA   THE MAX VALUE FOR WHICH A IS DIMENSIONED FOR
      DIMENSION A(NDIMA,1)
       DO 100 I=1,N
       DO 100 J=2,N
       IF(I-J)10,20,20
10     JJ=I-1
       IF(JJ.EQ.0)GO TO 60
       GO TO 50
20     JJ=J-1
50     DO 40 K=1,JJ
40     A(I,J)=A(I,J)-A(I,K)*A(K,J)
       IF(I.GE.J)GO TO 100
```

```
60      A(I,J)=A(I.J)/A(I,I)
100     CONTINUE
        RETURN
        END




       SUBROUTINE SOLVE(A,B,N,NDIMA,NBIMA)
C       THIS SUBROUTINE SOLVES AX=B WHEN A IS GIVEN IN FACTORED FORM
C       AND RETURNS X IN B
C       THE ARGUMENTS ARE
C                     A  THE N BY N FACTORIZED MATRIX
C                     B THE N BY 1 VECTOR B
C                     N THE DIMENSION OF MATRIX A
C                     NDIMA  THE MAX VALUE FOR WHICH A IS DIMENSIONED FOR
C                     NBIMA  THE MAX VALUE FOR WHICH B IS DIMENSIONED FOR
       DIMENSION A(NDIMA,1),B(NBIMA)
C       FORWARD ELIMINATIOM STEPS
        B(1)=B(1)/A(1,1)
        DO 2 I=2,N
        JJ=I-1
        DO 1 K=1,JJ
1       B(I)=B(I)-A(I,K)*B(K)
2       B(I)=B(I)/A(I,I)
C       BACK SUBSTITUTION STEPS
        N1=N-1
        DO 5 I=1,N1
        J=N-I
        JJ=J+1
        DO 4 K=JJ,N
4       B(J)=B(J)-A(J,K)*B(K)
5       CONTINUE
        RETURN
        END




        SUBROUTINE ADDER(DELTA,IBRA)
C       THIS SUBROUTINE ADDS THE MINIMUM COST LINES TO THE SYSTEM
        IMPLICIT INTEGER(A-Z)
        COMPLEX YBUS,S,VALUE,TYPE
        REAL SMALL,VAR,QUOT,DELTA,AD1,VAR1,VAR2,BIG,VAT,STYPE
        PARAMETER ND=30,NB=66
        COMMON/YBUS/YBUS(ND,ND)
        COMMON/AD1/AD1(NB)
        COMMON/IAD/IAD(NB)
        COMMON/TYPE/TYPE(NB,4)
        COMMON/STYPE/STYPE(NB,5)
        IPOS=0
        SMALL=10E+8
        DO 400 M=1,4
        IF(AIMAG(TYPE(IBRA,M)).EQ.0.)GO TO 401
        S=1./TYPE(IBRA.M)
        VAR=ABS(AIMAG(S))
        QUOT=VAR-DELTA
```

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```
      IF(QUOT.LT.0.)GO TO 400
      IPOS=1
      IF(VAR.LT.SMALL)GO TO 402
      GO TO 400
402   SMALL=VAR
      MX=M
400   CONTINUE
401   CONTINUE
      IF(IPOS.EQ.0)GO TO 403
      S=1./TYPE(IBRA,MX)
      CALL ILO(IBRA,NS,NR)
      YBUS(NS,NR)=YBUS(NS,NR)-S
      YBUS(NR,NS)=YBUS(NR,NS)-S
      YBUS(NS,NS)=YBUS(NS,NS)+S
      YBUS(NR,NR)=YBUS(NR,NR)+S
      YBUS(NS,NS)=YBUS(NS,NS)+STYPE(IBRA,MX)
      YBUS(NR,NR)=YBUS(NR,NR)+STYPE(IBRA,MX)
      STYPE(IBRA,5)=STYPE(IBRA,5)+STYPE(IBRA,MX)
      AD1(IBRA)=AD1(IBRA)+ABS(AIMAG(S))
      IF(IAD(IBRA).EQ.0)IAD(IBRA)=MX
      II=IAD(IBRA)
      VAR1=ABS(AIMAG(S))
      S=1./TYPE(IBRA,II)
      VAR2=ABS(AIMAG(S))
      IF(VAR1.LT.VAR2)IAD(IBRA)=MX
      WRITE(6,490)MX,IBRA,TYPE(IBRA,MX)
490   FORMAT(57X,'I',' ADD 1 LINE OF TYPE',I3,' IN BRANCH',I3,' WHOSE R
     1AND X ARE',2F9.5,5X,'I',/)
      RETURN
403   BIG=-10E+8
      MX=0
      DO 404 M=1,4
      IF(AIMAG(TYPE(IBRA,M)).EQ.0.)GO TO 404
      S=1./TYPE(IBRA,M)
      VAR=ABS(AIMAG(S))
      IF(VAR.LT.BIG)GO TO 404
      BIG=VAR
      MX=M
404   CONTINUE
C     NEXT STATMENTS CALCULATE THE NUMBER OF LINES TO BE ADDED
      S=1./TYPE(IBRA,MX)
      VAR=ABS(AIMAG(S))
      VAT=DELTA/VAR
      I=VAT
      I=I+1
      VALUE=I*S
      CALL ILO(IBRA,NS,NR)
      YBUS(NS,NR)=YBUS(NS,NR)-VALUE
      YBUS(NR,NS)=YBUS(NR,NS)-VALUE
      YBUS(NS,NS)=YBUS(NS,NS)+VALUE
      YBUS(NR,NR)=YBUS(NR,NR)-VALUE
      YBUS(NS,NS)=YBUS(NS,NS)+(I*STYPE(IBRA,MX))
      YBUS(NR,NR)=YBUS(NR,NR)+(I*STYPE(IBRA,MX))
      STYPE(IBRA,5)=STYPE(IBRA,5)+(I*STYPE(IBRA,MX))
      AD1(IBRA)=AD1(IBRA)+ABS(AIMAG(VALUE))
      IF(IAD(IBRA).EQ.0)IAD(IBRA)=MX
      II=IAD(IBRA)
      VAR1=ABS(AIMAG(S))
      S=1./TYPE(IBRA,II)
      VAR2=ABS(AIMAG(S))
      IF(VAR1.LT.VAR2)IAD(IBRA)=MX
      WRITE(6,491)I,MX,IBRA,TYPE(IBRA,MX)
491   FORMAT(57X,'I',' AND',I3,' LINES OF TYPE',I2,' IN BRANCH',I3,' WHO
     1SE R AND X ARE',2F9.5,'I')
      RETURN
      END




      SUBROUTINE JACCB
C     THIS SUBROUTINE CALCULATES THE SENSITIVITY MATRIX B SHOWING THE
C     VARIATIONS OF PHASE ANGLE DIFFERENCES WITH RESPECT TO  THE CHANGES
C     IN IN LINE ADMITTANCES
C     MATRIX B HAS DIMENSION OF NBRA*NBRA
      IMPLICIT INTEGER(A-Z)
      REAL ERR,BP,A,B,XP,XQ
      REAL TOL,DRAD,MVAB
      PARAMETER ND=30,NB=56
      COMMON/BP/BP(ND,ND)
      COMMON/A/A(NB,ND)
      COMMON/INP/INP(ND)
      COMMON/B/B(NB,NB)
      COMMON/XP/XP(NB)
      COMMON/XQ/XQ(NB)
      COMMON/SCLR/NODE,NBRA,TOL,DRAD,LIMIT,NYEAR,MVAB,NSUB,IDEB
      COMMON/SCLR2/CP,CQ
      CALL XFLOW
      WRITE(14,-)((BP(I,J),J=1,CP),I=1,CP)
      CALL SINV(BP,XQ,CP,ND,NB)
      DO 420 I=1,CP
      DO 421 J=1,NBRA
      ERR=0.
      DO 422 K=1,CP
      INT=INP(K)
      ERR=BP(I,K)*A(J,INT)+ERR
C     HERE A IS A TRANSPOSE
422   CONTINUE
      B(I,J)=ERR
421   CONTINUE
420   CONTINUE
      REWIND 14
      READ(14,-)((BP(I,J),J=1,CP),I=1,CP)
      REWIND 14
      DO 423 I=1,NBRA
      DO 424 J=1,NBRA
      ERR=0.
      DO 425 K=1,CP
      INT=INP(K)
      ERR=A(I,INT)*B(K,J)+ERR
425   CONTINUE
      XQ(J)=ERR
424   CONTINUE
      WRITE(14,-)
      WRITE(14,-)(XQ(K),K=1,NBRA)
423   CONTINUE
      REWIND 14
      READ(14,-)((B(I,J),J=1,NBRA),I=1,NBRA)
      REWIND 14
      DO 426 I=1,NBRA
      DO 427 J=1,NBRA
      B(I,J)=B(I,J)*XP(J)
427   CONTINUE
426   CONTINUE
      RETURN
      END



      SUBROUTINE SINV(A,B,N,NDIMA,NBIMA)
       DIMENSION A(NDIMA,1),B(NBIMA)
C      THIS SUBROUTINE INVERTS A FACTORIZED MATRIX
C      AND RETURNS IT IN ITSELF
C      THE ARGUMENTS ARE
C                 A  THE FACTORIZED N BY N MATRIX A
C                 B  A DUMMY VECTOR
C                 N  THE DIMENSION OF MATRIX A
C                 NDIMA  THE MAX VALUE FOR WHICH A IS DIMENSIONED FOR
C                 NBIMA THE MAX VALUE FOR WHICH B IS DIMENSIONED FOR
      REWIND 14
       DO 8 I=1,N
       DO 7 J=1,N
       B(J)=0.
       IF(I.EQ.J)B(J)=1.
7      CONTINUE
       CALL SOLVE(A,B,N,NDIMA,NBIMA)
      WRITE(14,-)(B(K),K=1,N)
8     CONTINUE
      REWIND 14
      READ(14,-)((A(I,J),I=1,N),J=1,N)
      REWIND 14
       RETURN
       END


      SUBROUTINE ILO(ILINE,NSND,NRCVD)
      IMPLICIT INTEGER(A-Z)
      REAL TOL,DRAD,MVAB
      REAL A
      PARAMETER ND=30,NB=66
      COMMON/A/A(NB,ND)
      COMMON/SCLR/NODE,NBRA,TOL,DRAD,LIMIT,NYEAR,MVAB,NSUB,IDEB
      NSND=0
      NRCVD=0
      DO 30 JO=1,NODE
      IF(A(ILINE,JO).EQ.0.)GO TO 30
      IF(A(ILINE,JO).EQ.1.)NSND=JO
      IF(A(ILINE,JO).EQ.-1.)NRCVD=JO
30    CONTINUE
      RETURN
      END
      SUBROUTINE XSOL(J)
C     THIS SUBROUTINE REPLACES THE LINEAR PROGRAM TO FIND A SET OF
C     MINIMUM COST CAPACITY ADDITIONS
      IMPLICIT INTEGER(A-Z)
      REAL TOL,DRAD,MVAB
      REAL DIF,PSTAR,PHMIN,VAR,ARATIO,B,COST,DACTOR,Q,DELTA
      REAL XP
      PARAMETER ND=30,NB=66
      COMMON/ITEMP/ITEMP(NB)
      COMMON/PSTAR/PSTAR(NB)
      COMMON/PHMIN/PHMIN(NB)
      COMMON/B/B(NB,NB)
      COMMON/COST/COST(NB)
      COMMON/SCLR/NODE,NBRA,TOL,DRAD,LIMIT,NYEAR,MVAB,NSUB,IDEB
      COMMON/XP/XP(NB)
      DO 1 K=1,NBRA
      ITEMP(K)=0
      IF(PSTAR(K).GT.0.)GO TO 2
      GO TO 1
  2   ITEMP(K)=1
      CALL ILO(K,NSND,NRCVD)
      WRITE(6,92)K,NSND,NRCVD
 92   FORMAT(10X,'OVER LOAD IN BRANCH',I3,' BETWEEN BUSES',I3,' AND',I3,
     1' I',72X,'I')
  1   CONTINUE
C     ITEMP SHOWS THE OVERLOADED BRANCHES BY ASSIGNING A 1 TO THE CORRES
C     PONDING ELEMENTS
      DO 3 I=1,NBRA
      IF(ITEMP(I).EQ.1)GO TO 4
      GO TO 3
  4   VAR=0.
      DO 5 JJ=1,NBRA
      IF(JJ.EQ.I)GO TO 13
      IF(B(I,JJ).GT.0.)GO TO 5
 13   CONTINUE
      ARATIO=((B(I,JJ)*1E+6)**2)/((COST(JJ)*1E-4)*PSTAR(I))
      IF(ARATIO.GT.VAR) GO TO 6
      GO TO 5
  6   VAR=ARATIO
      ITEMP(I)=JJ
  5   CONTINUE
C     ITEMP(I) NOW SHOWS THE BRANCHES TO BE VARIED, ITEMP, FOR OVERLOADS
C     IN THE I TH BRANCH
  3   CONTINUE
      IDIV=0
      DO 20 I=1,NBRA
      IF(ITEMP(I).GT.0) IDIV=IDIV+1
 20   CONTINUE
      VAR=0.
      DO 7 I=1,NBRA
      IF(ITEMP(I).GT.0) GO TO 8
      GO TO 7
  8   IVAL=ITEMP(I)
      Q=0.
      DO 9 II=1,NBRA
      IF(ITEMP(II).GT.0)Q=Q+ABS(B(II,IVAL))
  9   CONTINUE
      DACTOR=Q/IDIV
      IF(DACTOR.GT.VAR)GO TO 11
      GO TO 7
11    VAR=DACTOR
      IBRA=IVAL
      IX=I
C     IX IS THE OVERLOADED BRANCH, IBRA IS THE BRANCH TO BE CHANGED
 7    CONTINUE
      DELTA=PSTAR(IX)/ABS(B(IX,IBRA))
      CALL ILO(IBRA,NSND,NRCVD)
      WRITE(6,80)DELTA,IBRA,NSND,NRCVD
80    FORMAT(57X,'I MIN',E10.4,' P.U. SUSCEPTANCE IN BRANCH',I3,' BETWEE
     1N BUSES',I3,' AND',I3,'     I')
      CALL ADDER(DELTA,IBRA)
      RETURN
      END
```

```
                        SUBROUTINE XOUT
      IMPLICIT INTEGER(A-Z)
      REAL GARB
      REAL XQ,PSTAR,B,GMAX,PHMIN,XP,VAR
      REAL STYPE,TOL,DRAD,MVAB
      REAL EC
      REAL VUP,VLO
      REAL DEL,YS
      REAL NPHMIN,Z
      COMPLEX YBUS,TYPE,S
      PARAMETER ND=30,NB=66
      COMMON/STYPE/STYPS(NB,5)
      COMMON/TYPE/TYPE(NB,4)
      COMMON/ITEMP/ITEMP(NB)
      COMMON/B/B(NB,NB)
      COMMON/PHMIN/PHMIN(NB)
      COMMON/PSTAR/PSTAR(NB)
      COMMON/GMAX/GMAX(NB)
      COMMON/YBUS/YBUS(ND,ND)
      COMMON/XP/XP(NB)
      COMMON/GARB/GARB(NB)
      COMMON/EC/EC(ND)
      COMMON/ISO/ISO
      COMMON/SCLR3/VUP,VLO
      COMMON KPOINT
      COMMON/SCLR/NODE,NBRA,TOL,DRAD,LIMIT,NYEAR,MVAB,NSUB,IDEB
      COMMON/SCLR2/CP,CQ
      COMMON/IOUTER/IOUTER
      COMMON/DEL/DEL(ND)
      COMMON/NPHMIN/NPHMIN(NB)
      JFL=3
      IF(KPOINT.EQ.1)GO TO 400
      CALL JACOB
       CALL CON
      IF(IOUTER.LE.3)GO TO 40
      JFL=IOUTER
```

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```
40    CONTINUE
      WRITE(6,700)
700    FORMAT(//,10X,48('*'),/,10X,'* OUTAGE IN BRANCH      * OVERLOAD IN
     1 BRANCH    *',/,10X,48('*'))
      NTERM=0
C     THE HIGHEST CAPACITY LINE IS REMOVED FOR OUTAGE TEST
      DO 510 I=1,NBRA
      ITEMP(I)=0
      GARB(I)=0.
510   PSTAR(I)=0.
      DO 2 I=1,NBRA
      VAR=0.
      DO 1 JJ=1,NBRA
       IF(NPHMIN(JJ).LT.1E-6)GO TO 1
      VAR=VAR+(ABS(B(JJ,I))*1E+6)*(XP(JJ)*XP(JJ)/(NPHMIN(JJ)*NPHMIN(JJ))
     1)
1     CONTINUE
       VAR=VAR*GMAX(I)/NBRA
      GARB(I)=VAR
2     CONTINUE
C     GARB(I) NOW SHOWS THE RELATIVE EFFECT OF BRANCH I ON THE REST OF SYSTEM
C     THE FOLLOWING STEPS CHOOSE THE BRANCH WITH THE LARGEST EFFECT,
C     OUT IT AND CALCULATE THE LOADFLOW. IN CASE OF OVERLOADS REPEAT FOR
C     THE NEXT MOST EFFECTIVE LINE
20    VAR=1E-8
      IX=0
      KFLAG=0
      DO 3 I=1,NBRA
      IF(GARB(I).LT.VAR.OR.ITEMP(I).EQ.1)GO TO 3
      VAR=GARB(I)
      IX=I
      KFLAG=1
3     CONTINUE
C     HERE TEST IS MADE TO SEE IF ALL BRANCH OUTAGES HAVE CAUSED OVERLOADS
      IF(KFLAG.EQ.0)GO TO 5
      ITEMP(IX)=1
      IF(GMAX(IX).LT.1E-6)GO TO 20
      IFLAG=0
C     HERE THE LARGEST CAPACITY LINE IS SELECTED
      DO 10 I=1,4
      VAR=1.-GMAX(IX)*AIMAG(TYPE(IX,I))
      IF(VAR.LT.1E-6)GO TO 11
10    CONTINUE
      WRITE(6,12)IX
12    FORMAT(/,'*** LARGEST CAPACITY LINE IN BRANCH',I3,' CANNOT BE  LO-
     1CATED. STOP')
      STOP
11    CONTINUE
      JX=I
      CALL ILO(IX,NS,NR)
      WRITE(6,701)IX
701    FORMAT(10X,'*',8X,I2,12X,'*',23X,'*')
41    CONTINUE
      IF(NS.EQ.0.OR.NR.EQ.0)GO TO 14
      GO TO 16
14    WRITE(6,15)IX
15    FORMAT(/,'** TERMINAL NODES OF BRANCH',I3,' CANNOT BE LOCATED')
      STOP
```

```
16    CONTINUE
      S=1./TYPE(IX,JX)
      YBUS(NS,NR)=YBUS(NS,NR)+S
      YBUS(NR,NS)=YBUS(NR,NS)+S
      YBUS(NS,NS)=YBUS(NS,NS)-S
      YBUS(NR,NR)=YBUS(NR,NR)-S
      YBUS(NS,NS)=YBUS(NS,NS)-STYPE(IX,JX)
      YBUS(NR,NR)=YBUS(NR,NR)-STYPE(IX,JX)
      STYPE(IX,5)=STYPE(IX,5)-STYPE(IX,JX)
      IF(ABS(AIMAG(YBUS(NS,NR))).LT.1E-4)IFLAG=1
      CALL XFLOW
      CALL CON
      IF(ISO.EQ.1)GO TO 500
      DO 511 J=1,NBRA
      IF(J.EQ.IX.AND.IFLAG.EQ.1)GO TO 511
      IF(ABS(XP(J)).LT.NPHMIN(J))GO TO 511
      Z=ABS(XP(J))-NPHMIN(J)
      IF(Z.GT.PSTAR(J))PSTAR(J)=Z
C     HERE PSTAR SHOWS MAXIMUM DEVIATIONS
511   CONTINUE
500   CONTINUE
      YBUS(NS,NR)=YBUS(NS,NR)-S
      YBUS(NR,NS)=YBUS(NR,NS)-S
      YBUS(NS,NS)=YBUS(NS,NS)+S
      YBUS(NR,NR)=YBUS(NR,NR)+S
      YBUS(NS,NS)=YBUS(NS,NS)+STYPE(IX,JX)
      YBUS(NR,NR)=YBUS(NR,NR)+STYPE(IX,JX)
      STYPE(IX,5)=STYPE(IX,5)+STYPE(IX,JX)
      IF(ISO.EQ.0)GO TO 600
      WRITE(6,490)JX,IX,TYPE(IX,JX)
490   FORMAT(57X,'I',' ADD 1 LINE OF TYPE',I3,' IN BRANCH',I3,' WHOSE R
     1AND X ARE',2F9.5,1X,'I')
      ISO=0
      GO TO 500
600   CONTINUE
      DO 4 I=1,NBRA
      IF(I.EQ.IX.AND.IFLAG.EQ.1)GO TO 4
      IF(ABS(XP(I)).GT.NPHMIN(I))GO TO 32
      GO TO 4
32    KTERM=0
      K2=I
      DO 42 K3=K2,NBRA
      IF(K3.EQ.IX.AND.IFLAG.EQ.1)GO TO 42
      IF(ABS(XP(K3)).LT.NPHMIN(K3))GO TO 42
      WRITE(6,702)K3
702    FORMAT(10X,'*',22X,'*',10X,I2,11X,'*')
42    CONTINUE
       WRITE(6,704)IX
704    FORMAT(10X,'*',22X.'*',23X,'*',4X,40('*'),/,10X,'*',22X,'*',23X,'*
     1',4X,'*',5X,'INTERMEDIATE LOAD FLOW RESULTS    *',/,10X,'*',22X,'*'
     2,23X,'*',4X,'*',5X,'FOR OUTAGE IN BRANCH',I4,6X,'*',/,10X,'*',22X,
     3'*',23X,'*',4X,'* BUS',5X,'VOLT. P.U.',6X,'ANGLE DEG.    *',/,10X,'
     4*',22X,'*',23X,'*',4X,40('*'))
       DO 45 K4=1,NODE
       YS=DEL(K4)*DRAD
       WRITE(6,703)K4,EC(K4),YS
703     FORMAT(10X,'*',22X,'*',23X,'*',4X,'*',I3,4X,F12.5,6X,F10.5,'    *'
     1)
45     CONTINUE
```

```
      GO TO 20
4     CONTINUE
      KTERM=KTERM+1
      IF(KTERM.LT.JFL)GO TO 20
5     RETURN
400   CONTINUE
      DO 421 I=1,NBRA
      IF(GMAX(I).LT.1E-6)GO TO 421
      CALL ILO(I,NS,NR)
C     HERE THE LARGEST CAPACITY LINE IS SELECTED
      DO 410 J=1,4
      VAR=1.-GMAX(I)*AIMAG(TYPE(I,J))
      IF(VAR.LT.1E-6)GO TO 411
410   CONTINUE
      WRITE(6,12)I
      STOP
411   JX=J
C      WRITE(-,101)I,NS,NR
101        FORMAT(' BRANCH,NS,NR',3I4)
      S=1./TYPE(I,JX)
      YBUS(NS,NR)=YBUS(NS,NR)+S
      YBUS(NR,NS)=YBUS(NR,NS)+S
      YBUS(NS,NS)=YBUS(NS,NS)-S
      YBUS(NR,NR)=YBUS(NR,NR)-S
      YBUS(NS,NS)=YBUS(NS,NS)-STYPE(I,JX)
      YBUS(NR,NR)=YBUS(NR,NR)-STYPE(I,JX)
      STYPE(I,5)=STYPE(I,5)-STYPE(I,JX)
      CALL XFLOW
      IF(ISO.EQ.1)GO TO 520
      DO 412 J=1,NODE
      IF(EC(J).GT.VUP.OR.EC(J).LT.VLO)CALL VCOR
412   CONTINUE
520   CONTINUE
      YBUS(NS,NR)=YBUS(NS,NR)-S
      YBUS(NR,NS)=YBUS(NR,NS)-S
      YBUS(NS,NS)=YBUS(NS,NS)+S
      YBUS(NR,NR)=YBUS(NR,NR)+S
      YBUS(NS,NS)=YBUS(NS,NS)+STYPE(I,JX)
      YBUS(NR,NR)=YBUS(NR,NR)+STYPE(I,JX)
      STYPE(I,5)=STYPE(I,5)+STYPE(I,JX)
      IF(ISO.EQ.0)GO TO 521
      WRITE(6,490)JX,I,TYPE(I,JX)
      ISO=0
      GO TO 520
521   CONTINUE
421   CONTINUE
      WRITE(6,414)
414   FORMAT(10X,'NO OVER OR UNDER VOLTAGES',22X,'I',72X,'I')
      RETURN
      END
```

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```
      SUBROUTINE CON
C     THIS SUBROUTINE CONVERTS VA RATINGS TO REAL POWER RATINGS
      IMPLICIT INTEGER(A-Z)
      REAL EC,DEL,AMU,VP,AM,NUM,DEN,PHMIN,NPHMIN
      PARAMETER ND=30,NB=66
      COMMON/EC/EC(ND)
      COMMON/DEL/DEL(ND)
      COMMON/PHMIN/PHMIN(NB)
      COMMON/NPHMIN/NPHMIN(NB)
      COMMON/AMU/AMU(NB)
      COMMON/SCLR/NODE,NBRA,TOL,DRAD,LIMIT,NYEAR,MVAB,NSUB,IDEB
      DO 10 I=1,NBRA
      NPHMIN(I)=1E+6
      IF(PHMIN(I).GT.1E+5)GO TO 10
      CALL ILO(I,NS,NR)
      IF(DEL(NS).GT.DEL(NR))GO TO 11
      IREV=NS
      NS=NR
      NR=IREV
11    VP=EC(NS)*EC(NR)
      AM=DEL(NS)-DEL(NR)
      NUM=EC(NS)**2-(AMU(I)*VP*AM)-VP
      DEN=AMU(I)*(EC(NS)**2)-(AMU(I)*VP)+(VP*AM)
      DEN=ABS(DEN)
      NUM=SQRT(NUM**2+DEN**2)
      NUM=DEN/NUM
      NPHMIN(I)=PHMIN(I)*NUM
      IF(AM.LT.1E-6)NPHMIN(I)=PHMIN(I)
10    CONTINUE
      RETURN
      END
```

```
      SUBROUTINE VCOR
      IMPLICIT INTEGER(A-Z)
      REAL TOL,DRAD,MVAB
      REAL EC,VAR,VUP,VLO,XQ,BPP,B
      COMPLEX S1,YBUS
      PARAMETER ND=30,NB=66
      COMMON/INQ/INQ(ND)
      COMMON/EC/EC(ND)
      COMMON/XQ/XQ(NB)
      COMMON/BPP/BPP(ND,ND)
      COMMON/YBUS/YBUS(ND,ND)
      COMMON/SCLR/NODE,NBRA,TOL,DRAD,LIMIT,NYEAR,MVAB,NSUB,IDEB
      COMMON/SCLR3/VUP,VLO
6     KPOINT=1
      DO 7 I=1,NODE
7     XQ(I)=0.
      CALL BUILD(CP,CQ)
      DO 1 I=1,CQ
      INT=INQ(I)
      VAR=EC(INT)
C     THE FOLLOWING STATMENTS ARE TO CHECK FOR OVER AND UNDER VOLTAGES
      B=VAR/VUP-1
      IF(B.GT.1.E-6)GO TO 10
      B=1-VAR/VLO
      IF(B.GT.1.E-6)GO TO 20
      GO TO 1
10    XQ(I)=VUP-VAR
      KPOINT=0
      WRITE(6,30) INT,VAR
30    FORMAT(10X,'OVER VOLTAGE AT BUS',I3,' MAGNITUDE',F8.5,'        I',7
     12X,'I')
      GO TO 1
20    XQ(I)=VLO-VAR
      KPOINT=0
      WRITE(6,40) INT,VAR
40    FORMAT(10X,'UNDER VOLTAGE AT BUS',I3,' MAGNITUDE',F8.5,'       I',7
     12X,'I')
1     CONTINUE
      IF(KPOINT.EQ.1)RETURN
      DO 2 I=1,CQ
      IF(XQ(I).EQ.0.)GO TO 2
      VAR=0.
      DO 3 J=1,CQ
      VAR=BPP(I,J)*XQ(J)+VAR
3     CONTINUE
      INT=INQ(I)
      B=VAR/EC(INT)
      WRITE(6,4)B,INT
4     FORMAT(57X,'I ADD',F12.5,' P.U.SUSCEPTANCE AT BUS',I3,30X,'I')
      S1=CMPLX(0.,B)
      YBUS(INT,INT)=YBUS(INT,INT)+S1
2     CONTINUE
      CALL XFLOW
      GO TO 6
      END



      SUBROUTINE COCAL
C     THIS SUBROUTINE CALCULATES THE COST COEFFICIENTS COST(I) FOR
C     EACH BRANCH
      IMPLICIT INTEGER(A-Z)
      REAL TOL,DRAD,MVAB
      REAL ZZ,DEL,XP,EN,CA,COST,AMU,ETA
      REAL A
      COMMON/SCLR/NODE,NBRA,TOL,DRAD,LIMIT,NYEAR,MVAB,NSUB,IDEB
      PARAMETER ND=30,NB=66
      COMMON/DEL/DEL(ND)
      COMMON/ETA/ETA
      COMMON/A/A(NB,ND)
      COMMON/XP/XP(NB)
      COMMON/EN/EN(NB)
      COMMON/CA/CA(NB)
      COMMON/AMU/AMU(NB)
      COMMON/COST/COST(NB)
      CALL XFLOW
      DO 101 J=1,NBRA
      ZZ=0.
      DO 103 K=1,NODE
      ZZ=(DEL(K)*A(J,K))*XP(J)+ZZ
103   CONTINUE
      COST(J)=(EN(J))*(CA(J)+(ETA*AMU(J))*((XP(J)**2)-2*ZZ))
101   CONTINUE
      RETURN
      END
```

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